The Governor's Task Force on Electric Reliability and Outage Preparedness

STATUS OF THE ELECTRIC GRID IN MASSACHUSETTS

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GOVERNOR'S TASK FORCE ON
ELECTRIC RELIABILITY AND OUTAGE PREPAREDNESS

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EXECUTIVE SUMMARY

On August 14, 2003, approximately 50 million people in the United States and Canada experienced an electric power blackout of approximately 61,800 megawatts of electric load. In the United States, the blackout affected residents of Ohio, Michigan, Pennsylvania, New York, Vermont, Connecticut, New Jersey and Massachusetts. In Massachusetts, approximately 19,000 customers in the Pittsfield and Springfield areas experienced the blackout, with an average power loss of 1.2 hours.

The following day, on August 15th, President George W. Bush and Prime Minister Jean Chrétien established a joint United States-Canada Power System Outage Task Force for the purpose of investigating the causes of the blackout and how to prevent future outages. The same day, Governor Mitt Romney announced the formation of a Massachusetts Task Force on Electric Reliability and Outage Preparedness chaired by Paul G. Afonso, Chairman of the Massachusetts Department of Telecommunications and Energy.

The mission of the Massachusetts Task Force on Electric Reliability and Outage Preparedness is assessing the potential for an event or series of events, inside or outside of New England, to escalate into a large-scale outage within Massachusetts. This report makes recommendations for reducing the Commonwealth's vulnerability to such cascading events, for containing such events, and for restoration of electric power after a large-scale outage, should one occur.

The Massachusetts Task Force on Electric Reliability and Outage Preparedness established the three working groups that began meeting in August 2003:[1]

- The Electric System Working Group, to assess the current electric system and infrastructure in Massachusetts;

- The Natural Gas Working Group, to examine whether a shortage in gas supply could result in a large scale electric outage in Massachusetts; and

- The Telecommunications Working Group, to examine the role that telecommunications facilities play in electric system reliability and the role of telecommunications in the electric system emergency response process.

This report is divided into three sections, one for each of the Working Groups. The Electric System Working Group report examines electric system infrastructure and operations in Massachusetts to determine the potential for an event or series of events, inside or outside of New England, to escalate into a large-scale outage within Massachusetts. The Electric System

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[1] Appendix 1 lists Working Group participants.

report provides an overview of the New England electric grid, summarizes projected electric needs for the next ten years, and provides information about the resources likely to be available to meet those needs. In addition, the Electric System report provides information regarding the design and operation of the devices that protect the electric system; electric system operation, maintenance and planning; and the role of ISO New England and the satellite operators in ensuring the reliable day-to-day operation of the bulk power system in New England. The Electric System report provides an overview of the reliability criteria to which the New England electric system is designed and operated; sets forth the maintenance practices used to ensure that generation, transmission, and distribution equipment are in proper working condition; and provides an overview of the coordinated transmission planning process for New England. The Electric System Working Group presents its reliability assessment and recommendations for reducing the probability of a large-scale electric outage in Massachusetts.

The Natural Gas Working Group report considers the extent of gas-fired generation in the region; the current and projected natural gas infrastructure; the sources of natural gas supply; the deliverability of natural gas to the region; the causes of and responses to natural gas interruptions; and mechanisms for communications between the natural gas and electric sectors.

The Telecommunications Working Group Report examines the role that telecommunications facilities play in electric system reliability and the role of telecommunications in the electric system emergency response process. To a lesser extent, the Telecommunications report also addresses telecommunications system reliability as it relates to the provision of services to electric companies.

This report contains the following eleven appendices: (1) List of Participants in the Working Groups; (2) Interim Report: Causes of the August 14th Blackout in the United States and Canada; (3) Blackout 2003, Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout; (4) the ISO New England RTEP03 Technical Report; (5) Reliability Assessment 2003 - 2012, North American Electric Reliability Council; (6) A Natural Gas Primer: The Components of the Natural Gas Delivery System; (7) New England Power Pool Generating Units by RTEP03 Sub-Area; (8) Proposed Enhancements to the New England and New York Natural Gas Systems; (9) Proposed LNG Import Terminal Projects for New England and Eastern Canada; (10) Firm vs. Non-Firm Gas Transportation: Rationale and Risks; and (11) Additional Comments of the Conservation Law Foundation and MASSPIRG.

The chief findings and recommendations of the three working groups are summarized below.

Summary of the Electric System Working Group Report

Relative to Ohio and other Midwestern states, New England was largely unaffected by the August 14th blackout. Sustained outages, totaling approximately 2,500 megawatts of load, were limited to southwestern Connecticut plus small areas in Connecticut, Massachusetts and Vermont. Electric service was restored rapidly in most affected areas. Approximately 2,500 megawatts of New England generation was shut down automatically to protect it from damage; however, no major equipment sustained serious damage.

After reviewing events in New England on August 14th, the Massachusetts Task Force on Electric Reliability and Outage Preparedness has concluded that several factors worked to protect the New England area from more extensive blackouts experienced elsewhere in the Northeast. First, automatic relays shut down the lines between New York and New England to protect individual transmission lines from damage; this effectively isolated New England from the problems in the rest of the eastern United States. Second, the available electrical resources in New England following the blackout were sufficient to support the remaining load. Third, operators, utilities and generators throughout New England worked together to stabilize the New England bulk power system. System operators had sufficient information to assess the situation and the authority to take action to stabilize the New England bulk power system, including disconnecting customers. The combination of a single, centralized control area, well-defined responsibilities, well-trained operators and a long history of coordination made it possible to stabilize, and then quickly restore, the New England bulk power system.

Based on its analysis of electric system infrastructure, operations and planning in Massachusetts and New England, the Electric System Working Group offers the following recommendations:

- Massachusetts should participate actively in ongoing regional transmission planning activities and monitor the resolution of reliability issues identified through these activities.

- Massachusetts should closely monitor the resolution of emerging reliability issues in northeastern Massachusetts, particularly Boston.

- The Department of Telecommunications and Energy, the Energy Facilities Siting Board, and other interested parties should review all phases of the transmission siting process to determine whether it can be streamlined while protecting the integrity of the public review process and the interests of ratepayers, abutters, other affected parties, and the environment.

- Massachusetts should explore opportunities to create, through state and regional policy formulation and implementation, as well as system oversight, a more stable, more reliable electric system through investments in conservation, energy efficiency and distributed generation. Where institutional or regulatory barriers inhibit such investments, Massachusetts should seek to eliminate these barriers while protecting the interests of the ratepayers.

- Massachusetts should continue policies that encourage the development of renewable resources in order to advance the goal of a diverse generation base.

- Massachusetts, in coordination with ISO New England and Massachusetts electric companies, should continue to review locations where a concentration of infrastructure creates a significant reliability risk and make practical recommendations for reducing the risk of disruption at those locations.

- Massachusetts, in coordination with ISO New England and Massachusetts electric companies, should participate in the development and review of North American Electric Reliability Council/Northeast Power Coordinating Council reliability standards.

- Massachusetts should - absent mandatory reliability standards and appropriate regulatory oversight - ensure that both generation and transmission owners comply with standards for equipment maintenance and availability as established, reviewed and revised by the North American Electric Reliability Council/Northeast Power Coordinating Council.

- ISO New England should present information to system operators in the master/satellite and local distribution control centers regarding the real-time operation of the New England transmission system, to the extent this information is available.

- ISO New England should present information to system operators in the master/satellite and local distribution control centers regarding operation of systems outside of New England, to the extent this information is available.

- Transmission owners with assets in Massachusetts should continue to support coordinated operational control and authority over the real-time operation of the transmission grid through the ISO New England, or a successor organization.

- ISO New England should provide continuing training of ISO New England, satellites and generator operators to ensure that roles and responsibilities are clear and that operators are prepared to respond to unusual and significant power system events. ISO New England, in collaboration with Massachusetts electric companies and satellites, should develop training that focuses on incident management and communication; such training should be required for both primary and backup operators and should occur on a regular basis. Advanced tools such as training simulators may be helpful. ISO New England should continue to assess the effectiveness of operator training programs.

- ISO New England and Massachusetts electric utilities should investigate the costs and benefits of improved facilities and diagnostic tools and alarms for system operators.

- ISO New England and satellites should continue to conduct audits of the reliability of control center computer systems.

- Massachusetts electric, gas and telecommunications companies and ISO New England should explore opportunities to conduct a joint blackout restoration exercise similar to that conducted annually by New England electric providers.

- ISO New England and the satellite control centers should continue to review whether there are adequate blackstart resources to restore electric service to Massachusetts in a reasonable time following a widespread blackout.

- Massachusetts electric companies should continue to develop the capability to remotely control transmission and distribution facilities as cost-effective.

Summary of the Natural Gas Working Group Report

Natural gas is becoming the leading fuel for power generation in Massachusetts and New England. Therefore, electric system reliability for the Commonwealth depends, in part, on the interconnectedness between the electric system and gas supply within Massachusetts and the six-state New England region.

The region's natural gas infrastructure has grown considerably in recent years, with the addition of new pipelines from Canada and enhancements to the existing pipeline grid. Also, the region's sources of gas supply have diversified in recent years, contributing to a more reliable gas delivery system. The growth in natural gas infrastructure and diversified natural gas sources mitigates against potential disruptions in fuel supply and delivery and consequently increases the electric system's reliability. Maintaining and enhancing the region's natural gas infrastructure and diversity will support electric power reliability.

Based on its analysis of natural gas supply and deliverability in New England, the Natural Gas Working Group offers the following recommendations:

- Massachusetts and the gas industry should promote continued increases in pipeline capacity and deliverability to bring new supplies into and within Massachusetts and New England to meet market demand, which will enhance overall energy system security and reliability. Additional liquefied natural gas supplies may represent an important part of this supply mix.

- Massachusetts and the gas industry should encourage continued diversity of supply sources to enhance reliability.

- Electric and natural gas system operators should work to create greater communication and coordination in the region, which will help to ensure quick responses to emergency situations in either the gas or electric systems.

- Massachusetts and the gas industry should continue to encourage natural gas-related efficiency measures.

- Because firm versus interruptible contracts may affect the delivery of natural gas to power generators, ISO New England should review the existing market rules and procedures to determine if appropriate pricing signals would ensure that the necessary levels of gas supply and transportation agreements are held by power generators, while adhering to market principles. This, in turn, will help ensure that gas-side infrastructure is developed when and where it is needed to enhance overall power system reliability.

- As it seeks to enhance overall bulk electric grid reliability, ISO New England should review its existing market rules to ensure that proper incentives exist to promote a diversity of fuel sources used in generating electric power, including dual-fueled capability at generating stations.

Summary of the Telecommunications Working Group Report

The Interim Report of the United States-Canada Power System Outage Task Force did not identify telecommunications systems used by electric companies as a factor in the August 14th outage. However, in order to provide a complete analysis, the Telecommunications Working Group examined the role of telecommunications in electric system reliability and emergency response. Overall, the examination did not reveal major areas of concern in Massachusetts. However, the Telecommunications Working Group has identified certain issues for which it offers specific recommendations which may require further study.

Based on its analysis of the role that telecommunications facilities play in electric system reliability and the emergency response process, the Telecommunications Working Group offers the following recommendations:

- Electric utilities and their telecommunications providers should carefully assess whether redundancy should be built into telecommunications networks, particularly for data communications.

- Electric utilities and their telecommunications providers should work to upgrade their data and voice communications systems used for promoting electric system reliability and for emergency response to incorporate up-to-date, more flexible technologies.

- Electric utilities and their telecommunications providers should continue to study the issues of redundancy and upgrading their data and voice communications systems.

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INTRODUCTION

On August 14, 2003, approximately 50 million people in the United States and Canada experienced an electric power blackout of approximately 61,800 megawatts ("MW")[2] of electric load. In the United States, the blackout affected residents of Ohio, Michigan, Pennsylvania, New York, Vermont, Connecticut, New Jersey and Massachusetts. With respect to Massachusetts, approximately 19,000 customers in the Pittsfield and Springfield areas experienced the blackout, with an average power loss of 1.2 hours.

The following day, on August 15th, President George W. Bush and Prime Minister Jean Chrétien established a joint United States-Canada Power System Outage Task Force ("Joint Task Force") for the purpose of investigating the causes of the blackout and how to prevent future outages. The Joint Task Force divided its work into two phases. In the first phase, the Joint Task Force investigated the outage to determine the causes of the blackout and why it was not contained. The Interim Report of the Joint Task Force ("Interim Report") was released on November 19, 2003, containing the findings of the first phase.[3] In the second phase, the Joint Task Force will develop recommendations to reduce the possibility of future outages and minimize the scope of any that occur.

The Joint Task Force created three working groups: an electric system working group, a nuclear working group and a security working group. The Commissioner of the Massachusetts Division of Energy Resources ("DOER"), David O'Connor, represents the Commonwealth on the Joint Task Force's electric system and nuclear working groups.

On the same day that the Joint Task Force was formed, Governor Mitt Romney announced the formation of a Massachusetts Task Force on Electric Reliability and Outage Preparedness ("Massachusetts Task Force" or "Task Force"), chaired by Paul G. Afonso, Chairman of the Massachusetts Department of Telecommunications and Energy ("DTE"). The mission of the Massachusetts Task Force is to assess the potential for an event or series of events, inside or outside of New England, to escalate into a large-scale outage within Massachusetts. The Massachusetts Task Force is responsible for making recommendations for reducing the Commonwealth's vulnerability to such cascading events, for containing such events, and for restoration of electric power after a large-scale outage, should one occur. In light of the interconnected regional electric grid, the Task Force considered relevant issues for both the Commonwealth and the six-state New England region, specifically to the extent that these issues could affect Massachusetts.

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[2] Watt ("W") is a unit of power. One MW equals 1,000,000 W.

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003. See Appendix A.

The Massachusetts Task Force established the following three working groups:

- The Electric System Working Group, to monitor the federal investigation and to assess the current electric system and infrastructure in Massachusetts. This group has recommended actions to reduce the likelihood that electric system events within or outside New England could trigger a large-scale outage in Massachusetts.

- The Natural Gas Working Group, to examine the interrelationship between the electric system and gas supply. This group has assessed whether a shortage in gas supply could result in a large-scale electric outage in Massachusetts.

- The Telecommunications Working Group, to examine the role that telecommunications facilities play in electric system reliability and the role of telecommunications in the electric system emergency response process.

The Task Force did not assess (1) the security of the electric grid[4] against terrorist attacks,[5] (2) the likelihood of catastrophic damage in the face of hurricanes or other natural disasters, or (3) the need for specific new infrastructure projects.[6]

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4 A grid is an electric transmission and/or distribution network.

5 A terrorism-related assessment and coordination effort is currently being undertaken by the Executive Office of Public Safety.

6 The DTE and the Energy Facilities Siting Board ("Siting Board") will assess the need for new infrastructure projects at the proper time and venue pursuant to their statutory authority. The Siting Board reviews petitions to construct major energy infrastructure, including power plants and electric transmission lines. Siting Board review is conducted by a formal adjudicatory proceeding pursuant to G.L. c. 164, § 69G et seq.

REPORT OF THE ELECTRIC SYSTEM WORKING GROUP

I. ELECTRIC INDUSTRY OVERVIEW

Electric service is composed of three components: (1) generation service, associated with the power plants that produce the electricity; (2) transmission service, associated with the wires and facilities that transport the electricity at high voltages from power plants to distribution substations; and (3) distribution service, associated with the wires and facilities that transport the electricity at low voltages from distribution substations to customers' facilities and homes.

Historically, electric companies in Massachusetts operated as vertically integrated companies that provided the generation, transmission, and distribution functions as a single service. These vertically integrated companies participated in New England Power Pool ("NEPOOL"), a voluntary organization established in 1971 to coordinate the planning and operational dispatch functions of the electric companies in the six New England states. NEPOOL operated a master control center for New England which coordinated operations with four satellite control centers: Maine; New Hampshire; the Connecticut Valley Exchange ("CONVEX") which operates Connecticut and parts of western Massachusetts; and the Rhode Island, eastern Massachusetts and Vermont Energy control area ("REMVEC") which operates Rhode Island, eastern Massachusetts, Vermont, and parts of western Massachusetts.

In late 1997, the Massachusetts General Court passed the Electric Restructuring Act,[7] which resulted in the separation of the generation function from the formerly integrated electric company operations. Thus, in Massachusetts, transmission and distribution services currently are provided by the following investor-owned electric companies: National Grid (including Massachusetts Electric Company and Nantucket Electric Company), NSTAR (including Boston Edison Company, Commonwealth Electric Company, and Cambridge Electric Light Company), Western Massachusetts Electric Company, and Fitchburg Gas and Electric Light Company. In addition to the investor-owned electric companies, 48 communities have established 41 municipal electric utilities, serving approximately one million customers. Generation services are provided by a number of independent generators. Four other New England states are in various stages of restructuring their electric companies.

The restructured Massachusetts electric companies continue to participate in NEPOOL, which has been expanded to include investor-owned utility systems, municipal and consumer-owned systems, joint marketing agencies, power marketers, load aggregators, generation owners and end users. Through a restated NEPOOL agreement, certain NEPOOL functions

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7 St. 1997, c. 164.

have been transferred to an independent system operator, ISO New England ("ISO-NE"),[8] which administers the regional transmission tariff and market rules related to generator dispatch.[9] The master/satellite control area[10] configuration remains in place, with ISO-NE operating the master dispatch function.

The ISO-NE control area is part of the Eastern Interconnection, one of three distinct power grids or "interconnections" that comprise the power system in North America.[11] With limited exceptions, the three interconnections are electrically independent from each other. The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan to the Maritime Provinces. The ISO-NE control area benefits from its ties with the rest of the Eastern Interconnection, in that it can import power from other parts of North America both to ensure reliability and to acquire low-cost power.

To ensure reliable electric service in New England, ISO-NE and New England electric distribution companies plan and operate the New England grid in compliance with standards set by national and regional bodies. The North American Electric Reliability Council ("NERC") is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. NERC was established in 1968, in response to the Northeast blackout in 1965. NERC's members are ten Regional Reliability Councils. In the Northeast, the Northeast Power Coordinating Council ("NPCC") is active in

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8 This agreement assigns operational control of the New England power system to ISO-NE. On February 20, 2004, ISO-NE published its report, Blackout 2003, Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout. See Appendix A-1.

9 The master/satellite structure originated within the NEPOOL organization of integrated electric companies. With the creation of the ISO-NE, the master/satellite structure continues; ISO-NE is an independent master and the satellites operated by transmission owners in coordination with ISO-NE.

10 A control area is a geographic area within which a single entity, such as an Independent System Operator or Regional Transmission Organization ("RTO") balances generation and loads in real time to maintain reliable operation. A major function of the control area operators is system dispatch (balancing of power demand and generation) which involves communication with the power plant operators and interruptible load.

11 The other two North American interconnections are the Western Interconnection and the Electric Reliability Council of Texas ("ERCOT") Interconnection.

setting standards for the reliable operation and planning of the bulk electric system.[12] Operators located in the control areas actually maintain reliable operation of the system in real time while following NERC and regional council standards for reliability.

Regulation of the electric industry is shared by state regulatory authorities and the Federal Energy Regulatory Commission ("FERC"). Pursuant to G.L. c. 164, the DTE exercises general supervisory oversight of the integrated electric company operations, including retail electric service ratemaking and service quality to ensure reliable electric service. The ISO-NE coordinates electric company transmission operations pursuant to reliability standards promulgated by the NERC.

Pursuant to the Federal Power Act[13] and 42 U.S.C. §§ 7171-7173, the FERC regulates the rates of wholesale electric service in interstate commerce. The generation function operates with FERC oversight of market-based rates for wholesale electric service. Transmission rates for interstate electric service are jurisdictional to the FERC; however, the DTE exercises general oversight and ratemaking jurisdiction of retail electric service, in which FERC-approved transmission rates are included.

II. THE AUGUST 14th BLACKOUT

A. Introduction

On August 14, 2003, a combination of electric transmission line and generating facility outages in Ohio triggered a blackout affecting an estimated 50 million people in the Midwest and Northeast United States and in Ontario, Canada. Although eastern New York, northern New Jersey, southwestern Connecticut, and small portions of Massachusetts and Vermont lost power, electric service in most of New England was not affected. Section II, which draws heavily on the Interim Report, describes the events leading up to the blackout and explains why Massachusetts, and New England generally, were largely insulated from these events.

B. Events that Triggered the Blackout

The events that triggered the August 14th blackout began in the control area of the Midwest ISO ("MISO") and, specifically, of FirstEnergy ("FE"), an electric utility operating

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12 ISO-NE implements NPCC requirements through very specific planning and operating procedures. These procedures must also conform to the requirements of the restated NEPOOL agreement.

13 16 U.S.C. §§ 791a et seq.

company that serves much of northern Ohio. At approximately 1:41 p.m.,[14] FE's Eastlake 5 power plant (located in northern Ohio, along the shore of Lake Erie) dropped off-line, shifting and increasing power flows along FE's 345 kilovolt ("kV")[15] transmission system. Then, between 3:05 and 3:41 p.m., three of FE's 345 kV transmission lines in the Cleveland area faulted, apparently due to contact with overgrown trees along the transmission rights-of-way. As each line opened, it placed a higher load on the remaining high-voltage transmission lines.[16] Each outage caused voltages on the FE system to drop. The loss of the third transmission line seriously overloaded the 138 kV system serving Cleveland and Akron. Between 3:39 and 4:09 p.m., sixteen additional lines tripped, blacking out 600 MW of load in and around Akron. Finally, at 4:06 p.m., a fourth 345 kV line (known as the Sammis-Star line) opened due to overloading.

The Interim Report identifies the loss of the Sammis-Star line as the turning point at which system problems in northern Ohio initiated a cascading blackout across northeastern United States and into Canada.[17] On August 14th, large electrical flows were moving across FE's transmission system from generators in the south to serve load centers in northern Ohio, Michigan and Ontario. The opening of the Sammis-Star line closed off the last transmission pathway through FE's system. Electricity from northwest Pennsylvania, southern Ohio, eastern Michigan and Ontario then began to seek alternate paths to the northern Ohio loads.

Over the next five minutes, transmission lines in western Ohio, Michigan, Ontario, Pennsylvania, New York, and New Jersey were shut down by protective devices that sensed the power surges and interpreted them as various types of line faults. Protective devices also shut down generation in Michigan, Ohio, Pennsylvania, and New York.

By 4:10:45 p.m., the automatic shutdown of transmission lines across the northeast had split the Eastern Interconnection, which typically functions as a single, interconnected electric system, into two separate areas: (1) a northeastern "island" (including New York City, northern New Jersey, New York state, New England, eastern Michigan, Ontario, the Canadian

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[14] All times given in this report are in eastern daylight time.

[15] Nominal voltage is a distinctive design characteristic of a transmission line. Voltage is measured in volts ("V"). One kV equals 1,000 V.

[16] An "opened line" no longer has electricity flowing through it.

[17] A cascading blackout is a sequential tripping of numerous transmission lines and generators in a widening geographic area. A cascade can be triggered by just a few initiating events that cause power swings and voltage fluctuations in the system. Generators may trip in response to the fluctuations. This leads, in turn, to more power swings and more lines and generators being tripped.

Maritime provinces[18] and the Quebec system) that experienced power surges and frequency and voltage fluctuations; and (2) a southwestern area that was essentially unaffected by the blackout. Over the next few minutes, the northeastern island broke into several smaller electrical islands. In some areas, demand and local supply were reasonably matched, so that voltages and frequencies stabilized. In these areas, the electric system continued to operate. In other areas, the imbalance between demand and supply could not be overcome and generation and transmission facilities shut down at an increasing rate. These areas were blacked out.

The Interim Report identifies three problem areas that, together, caused the electric system to cascade out of control on August 14th. First, the report finds inadequate situational awareness at FE. NERC guidelines require control area operators such as FE to operate the electric grid at all times so as to ensure that the loss of a single major transmission line or generator will not threaten the stability of the system. When a transmission line or generator does open for any reason, the operators must, within 30 minutes, take whatever steps are needed (for example, shedding load or reducing generation) to ensure that the loss of another major transmission line or generator will not threaten the stability of the system.

Control area operators typically rely on sophisticated computer software to identify changes in the status of the transmission grid and determine whether action needs to be taken to compensate for such changes. However, on August 14th, FE's control room alarm system was not working properly and FE’s operators were unaware that it was not working properly, which meant that they also were unaware that transmission lines were out of service. Without information about the outaged lines, the operators did not know that they needed to take compensating action. In addition, because the operators did not know they had a growing stability problem, they did not alert or seek help from neighboring utilities or the MISO, the organization which coordinates power transmission in the region that includes FE.

The Interim Report also notes that FE received numerous reports from American Electric Power (“AEP”), MISO, and PJM[19]operators and its customers that, taken together, pointed to serious transmission problems on FE's system. However, FE failed to identify the emergency situation that it faced. Had FE operators used this information properly, they might have been able to take corrective action (e.g., disconnecting customers) that would have averted a total collapse of the system.

The Interim Report also identifies inadequate tree trimming as a cause of the blackout, because three of FE's 345 kV transmission lines faulted after contact with untrimmed trees.

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18 The Maritime provinces are New Brunswick, Nova Scotia and Price Edward Island.

19 PJM is the control area covering the Pennsylvania, Maryland and New Jersey region.

Finally, the Interim Report identifies inadequate diagnostic support from MISO, FE's reliability coordinator, as a cause of the outage. The report notes that MISO system analysis tools were not working effectively on August 14th and that MISO did not have real-time data on the status of certain transmission lines in systems under its oversight. MISO, therefore, was unable to detect and help correct the developing reliability problems on FE's system. In addition, the Interim Report finds that MISO and PJM lacked joint procedures to coordinate responses to transmission problems occurring near their common boundary.

C. The Effect of the Blackout in New England

On August 14, 2003, New England was experiencing high, but not extreme, temperatures. The forecasted peak load for ISO-NE (the control area that includes Massachusetts, Connecticut, Rhode Island, Vermont, New Hampshire, and Maine) was 23,000 MW. Actual load shortly before the blackout was 23,370 MW.

The ISO-NE control area is connected to the Eastern Interconnection by eight synchronized high-voltage transmission lines, including three running between New York and Vermont, two running between New York and Massachusetts, two running between New York's Pleasant Valley substation and Connecticut, and two underwater cables between southwest Connecticut and Long Island, New York.[20] Shortly before the outage, New England was exporting 400 MW to New York. At the same time, New England was importing 500 MW from the Canadian Maritimes, 1,400 MW over the Hydro-Quebec direct current ("DC") line,[21] and 250 MW over two other interconnections between Vermont and Quebec.

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[20] One of these two underwater cables (the recently-constructed Cross Sound cable) was not energized on August 14th.

[21] The Hydro-Quebec transmission line is a DC line carrying energy from hydro-power generators in Quebec. It does not function as part of the integrated alternating current ("AC") transmission network that serves the United States and Canada. For this reason, the Hydro-Quebec line was unaffected by the electric system instability in surrounding states and territories.

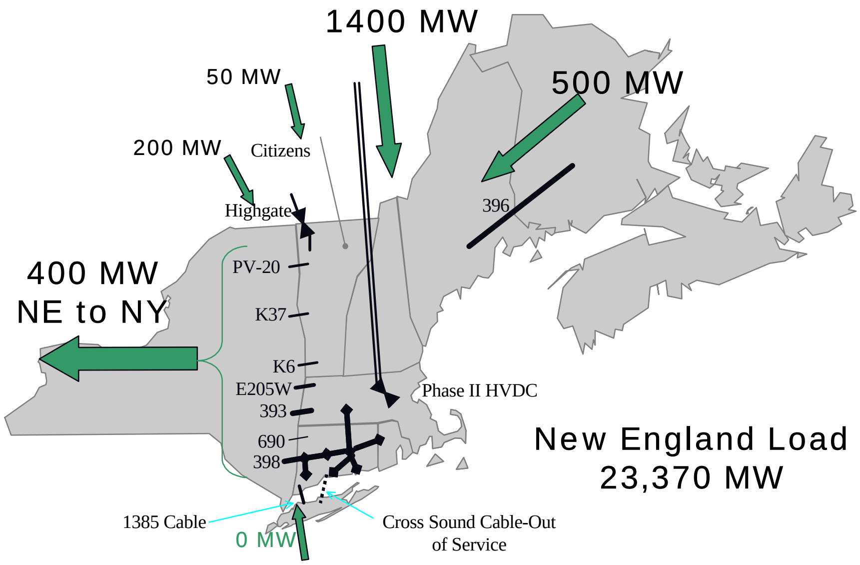

Figure 1 - Initial Conditions, 4:00 p.m. August 14, 2003

New England operators first became aware of electric system instability at 4:10:41 p.m., when more than 2,000 MW of electricity surged into New England from New York and electrical frequency rose to 60.3 hertz ("HZ").[22] Automatic systems in New Brunswick shut down 380 MW of generation in an attempt to return system frequency to normal levels.

Four seconds later, power flows reversed and 2,500 MW of electricity flowed out of New England and into New York. Electrical frequency dropped to 59.4 HZ. In the next five

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22 Hertz is a unit of frequency of electric current. In the United States and Canada, the electric system operates at a frequency of 60 HZ. When generation supply is equal to the load demand, the system operates at the designed frequency. Under ordinary circumstances, only very minor deviations from this frequency are experienced. An increase to 60.3 HZ indicated a serious imbalance between electricity demand and the generation serving it.

seconds, automatic protective relays on six of the eight transmission lines connecting New England to New York opened the lines and isolated most of New England and the Canadian Maritimes from the disturbances in the rest of the northeast. Protective devices also shut down generators in Connecticut, Massachusetts, Vermont, and New Brunswick.

The two remaining ties between New England and New York were a 345 kV line running from the Pleasant Valley substation in New York to the Long Mountain substation in southwestern Connecticut, and a 138 kV underwater cable running from the Northport substation in New York to the Norwalk substation in Connecticut. Within seconds, automatic protective devices tripped many of the 115 kV lines serving southwestern Connecticut,

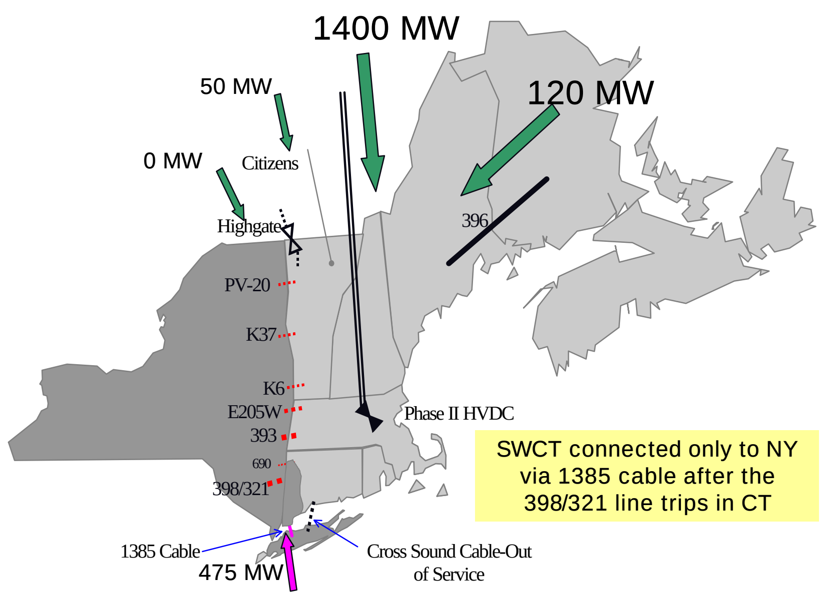

Figure 2 - Southwest CT Breakup 398/321 Trip (4:11:22 p.m.)

effectively severing the area from the rest of New England and leaving it tied to New York and Long Island. Within another minute, both the Long Mountain-Plum Tree line (which brought power into the 115 kV system) and the underwater cable connection with Long Island tripped and southwestern Connecticut lost all power.

Thus, by about 4:11 p.m. on August 14th, the six New England states (less southwestern Connecticut), together with the Canadian Maritimes, formed an electrical island separated from the rest of the United States and connected to Quebec by one major DC transmission line and one smaller interconnection. At this point, New England was no longer affected by frequency and voltage fluctuations caused by electrical instability in other states. However, in order to maintain electric service in the New England island, system operators needed to bring generation and load in New England into balance and to stabilize voltage levels.

Immediately after the separation, ISO-NE operators brought all available quick-start generation[23] on-line to provide local voltage support and manage overloads. During this period, the ISO-NE area had significantly more generation on-line than was needed to serve the remaining load; consequently, the system frequency was well above normal. Over the next few minutes, ISO-NE operators allowed automatic control systems to reduce generation in an attempt to bring the system frequency back to 60 HZ.[24] Within ten minutes, generation and demand were balanced and frequency was briefly at 60 HZ. However, as both generation levels and system loads changed, the system frequency fell below 60 HZ. At this point, ISO-NE operators took manual control of system dispatch and asked specific individual generators to increase generation until the system was in balance. ISO-NE operators also coordinated with their counterparts in New Brunswick to ensure that imports remained at 150 MW (rather than the 400 MW that were scheduled) until problems were under control.

At the same time, CONVEX[25] operators were taking actions in response to localized problems in western Massachusetts and Connecticut. In western Massachusetts, automatic protective devices removed two power plants located in Pittsfield and Agawam from the grid during the initial power surges. CONVEX operators noticed the resulting low voltages in the Pittsfield and Springfield areas. The operators also determined that, if one additional transmission line tripped, a number of transmission lines would be loaded above their

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[23] Quick-start generation typically is a non-spinning reserve capacity such as gas and combustion turbines and diesel generators that may be activated within 30 minutes to support system reliability during an emergency and/or a shortage of power supply.

[24] To enable customers to use the electricity as they wish at any moment, production by the generators must be scheduled or “dispatched” to meet constantly changing demands, typically on an hourly basis, and then fine-tuned throughout the hour, sometimes through the use of automatic generation controls to continuously match generation to actual demand.

[25] CONVEX represents approximately 30 percent of total New England load.

emergency ratings.[26] This situation violated NERC operating standards. In order to address both the operating standards violation and the low voltages, CONVEX operators disconnected about 19,000 customers in the Pittsfield and Springfield areas.

CONVEX operators took similar steps to address localized problems near Middletown and Hartford, Connecticut and southwestern Connecticut. In Connecticut, operators initially observed low voltages, resulting in part from the loss of significant generation in the area. The remaining Connecticut generation provided voltage support well in excess of normal capabilities until CONVEX operators were able to reduce local load. Once the load was dropped, voltages soared; however, the remaining generation was able to absorb the excess reactive power.[27] CONVEX operators ultimately disconnected approximately 405 MW of load in Connecticut and approximately 100 MW in western Massachusetts. These measures helped balance the New England island and saved it from a system-wide collapse.[28]

Once the New England island was stabilized, system restoration proceeded rapidly. The entire New England bulk transmission system was restored by 11:45 p.m on August 14th and the first tie line to New York was put in service at 1:53 a.m. on August 15th. All power in Massachusetts was restored by 3:00 a.m. on August 15th and by 4:00 a.m., power was restored to the majority of areas that had lost it (with the exception of approximately 100 MW of load in southwestern Connecticut). Emergency restoration procedures in Connecticut continued for another 24 hours.

The New England states were largely unaffected by the August 14th blackout. Sustained outages, totaling approximately 2,500 MW of load, were limited to southwestern Connecticut plus small areas in Connecticut, Massachusetts and Vermont. Electric service was restored rapidly in most affected areas. In addition, a number of large process users shut down automatically to protect their equipment from frequency and voltage fluctuations and returned

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[26] The short-term emergency rating of a transmission line is the maximal power flow that the line can sustain for a short period of time (e.g., for 15 minutes). During this time, actions should be taken to reduce the load back to normal level.

[27] A generator typically produces some mixture of "active" and "reactive" power and the balance between them can be adjusted at short notice to meet changing conditions. The generator's ability to absorb reactive power is limited due to the stability of its operation.

[28] Cooperation from generators in Connecticut was critical to stabilizing frequency and voltages in New England. For example, the operators of the Millstone power plant in Connecticut agreed to run at well below expected levels (and forego expected revenues) in order to support the system during the emergency.

to operation automatically once the electric system stabilized. Protective relays shut down approximately 2,500 MW of generation in New England; however, no major equipment sustained serious damage.

STATE	LOAD LOST
Massachusetts	100 MW (by CONVEX operators)
Connecticut	2,000 MW (automatic)
	405 MW (by CONVEX operators)
Vermont	70 MW

Table 1 - New England Load Lost on August 14, 2003

D. Factors that Helped Protect New England

Several factors worked to protect the New England area from more extensive blackouts. First, automatic relays acting to protect individual transmission lines effectively isolated New England from the rest of the Eastern Interchange. The protective relays on six of the eight lines connecting New England with the rest of the United States sensed what appeared to be faults when power first surged in and out of New England; and immediately took these lines out of service to protect them from damage. These automatic trips, combined with the collapse of the 115 kV transmission network in southwestern Connecticut, cut New England off electrically from the rest of the United States. Ironically, this cut-off (which under normal circumstances would have reduced the reliability of electric service in New England) worked in New England's favor by isolating it from the electrical instability in neighboring states. The automatic line trips also served their intended purpose of preventing damage to key electrical equipment. It should be noted that the isolation of the ISO-NE control area was a consequence of the trips of these six tie-lines. In other circumstances, a different set of lines could have tripped in a different sequence, with a different set of results.

Second, the surviving electrical resources in New England were sufficient to support the remaining load. Protective devices disconnected approximately 2,500 MW of generation during the first few minutes of instability and one tie-line with Quebec, carrying 200 MW of power into New England, tripped out of service. However, New England's main source of imported power – the DC line from Quebec – continued to operate. ISO-NE also had 2,000 MW of reserve generating capacity available to serve customers connected to that grid and surplus capacity of 2,100 MW above these required reserves – more than adequate capacity to compensate for these losses. In addition, there was adequate local generation (including emergency generation) in Connecticut, even after the southwestern Connecticut blackout, to manage the voltage swings created as large generators and loads returned to the system.

Third, operators, utilities and generators throughout New England worked together to stabilize the New England bulk power system. The New England transmission system, unlike that in the midwest, is operated as a single control area by ISO-NE. ISO-NE operators work closely with operators in the satellite control centers, at utility dispatch centers and at power plants. Central dispatch has been a feature of the New England electric system since the formation of NEPOOL in 1971. While the role of the centralized operator has evolved over time, the premise that the New England electric system must be run at all times in compliance with an established set of reliability standards has not changed. The master/satellite control center configuration, which places ISO-NE operators in a separate location from the four satellite control centers, helps prevent a single computer failure from blinding system operators.

During the August 14th blackout, operators at ISO-NE and the satellite control centers had sufficient information to assess the situation and the authority to take action to stabilize the New England bulk power system, even when that meant disconnecting customers or asking generators to operate well below contracted levels. System operators were trained to respond to emergency conditions and reliability standards were clearly established and consistent throughout the New England region. The combination of a single, centralized control area, well-defined responsibilities, well-trained operators and a long history of coordination made it possible to stabilize and then quickly restore the New England bulk power system.

III. ELECTRIC SYSTEM DESIGN AND OPERATION

The Electric System Working Group was charged with examining electric system infrastructure and operations in Massachusetts to determine the potential for an event or series of events, inside or outside of New England, to escalate into a large-scale outage within Massachusetts. Section III.A of this report provides an overview of the New England electric grid, which serves electric customers in Massachusetts and throughout New England. It summarizes projected electric needs for the next ten years and provides information about the resources likely to be available to meet those needs. These resources include both physical infrastructure (electric generators, transmission lines, distributed generation) and demand-side resources, including demand response and energy efficiency programs. Section III.A also provides information on the design and operation of the devices that protect important elements of the electric system (e.g., generators and transmission lines) by removing them from the grid.

Section III.B of this report focuses on electric system operation, maintenance and planning. It explains the role of ISO-NE and the satellite operators in ensuring the reliable day-to-day operation of the bulk power system in New England; provides an overview of the reliability criteria to which the New England electric system is designed and operated; and sets forth the maintenance practices used to ensure that generation, transmission, and distribution equipment are in proper working condition and able to provide reliable service to electric customers in Massachusetts. In addition, Section III.B provides an overview of the coordinated transmission planning process for New England. Finally, in Section III.C, the Electric System Working Group presents its reliability assessment and recommendations for reducing the probability of a large-scale electric outage in Massachusetts.

A. The New England Grid – Organization, Loads and Resources

1. Organization

The New England electric grid is a tightly integrated system that provides electric service to approximately 14 million people living in a six-state area covering over 68,000 square miles. Electricity is produced at over 350 generating units, which are connected to approximately 8,000 miles of high-voltage transmission lines. The New England electric grid is electrically interconnected with three other NPCC control areas: (1) the New York control area; (2) the New Brunswick control area; and (3) the Quebec system.[29] ISO-NE, the grid operator, is a member of the NPCC [30]

The New England transmission system includes virtually all of the networked electric systems in New England. It serves a diverse region that ranges from rural to dense urban, integrating widely dispersed and varied types of power supply resources to serve customer load. Approximately 20 percent of New England load originates in the three northern states (Maine, New Hampshire and Vermont), while 80 percent comes from the three southern states (Massachusetts, Connecticut and Rhode Island). For certain modeling purposes, ISO-NE divides New England into smaller sub-areas. These sub-areas do not necessarily coincide with any political or service area boundaries. They are used as a modeling tool to roughly reflect the existing transmission transfer capabilities of the bulk transmission system.[31] Figure 3,

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[29] The province of Quebec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection primarily by DC ties.

[30] The NPCC is one of ten regional reliability councils of NERC. NPCC control areas encompass the New England states and New York in the United States, and the provinces of New Brunswick, Nova Scotia, Ontario and Quebec in Canada.

[31] The sub-areas are a considerable simplification of the actual transmission network. The results of the transportation analyses of these sub-areas do not capture system constraints within the sub-areas, but rather reflect transfer capabilities between

(continued…)

below, shows the sub-areas of the New England region that ISO-NE uses in the transportation model-based analyses included in its Regional Transmission Expansion Plan ("RTEP")[32] reports. These sub-areas do not directly coincide with the load zones that have been established for market settlement purposes.

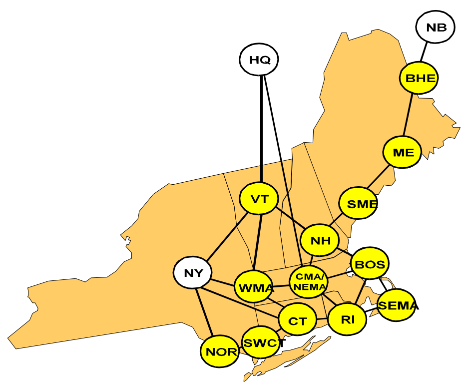

Figure 3 - RTEP Geographic Scope

BHE - Northeast Maine

ME - Western & Central Maine/ Saco Valley, New Hampshire

SME - Southeast Maine

NH - North, East, & Central New Hampshire/Eastern Vermont & Maine

VT - Vermont/Southwest New Hampshire

BOS - Greater Boston, including North Shore

CMA/NEMA - Central Massachusetts/ Northeast Massachusetts

WMA - Western Massachusetts

SEMA - Southeast Massachusetts/ Newport Rhode Island

RI - Rhode Island/bordering Massachusetts

CT - North and East Connecticut

SWCT - South Central Connecticut

NOR - Norwalk/Stamford, Connecticut

NB, HQ and NY - Represent the New Brunswick, Hydro Quebec and New York external Control Areas

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31 (…continued)
sub-areas. As such, transportation modeling results based on the sub-areas should be considered best-case results. Detailed transmission analyses are essential to capture more detailed system performance within and between the sub-areas. For purposes of assessing system performance, these more detailed transmission analyses conducted by ISO-NE are indifferent to the sub-area definitions.

32 The RTEP process is a comprehensive electrical engineering assessment comprised of numerous studies and analyses of New England's bulk electric power system. This process is discussed further in Section III.B.4, below.

2. System Demand and Load Forecasting

In order to reliably serve New England electric customers, ISO-NE and the Massachusetts electric companies must create accurate forecasts of the amount of electricity that will be needed on an hourly, daily and annual basis. As part of its planning process, ISO-NE develops a consistent set of energy and peak load forecasts for NEPOOL, for each of the New England states, and for the 13 RTEP sub-areas discussed above. The forecast combines (1) state historical electric load, economic, and weather data, (2) operating company historical load and weather data, (3) data filed with the FERC,[33] and (4) the effects of conservation and peak load management programs. It is both bottom-up (NEPOOL as the sum of the six states) and top-down (the RTEP sub-areas as a disaggregation of the operating companies within states).

Table 2, below, depicts current load forecasts for NEPOOL, the six New England states, and the RTEP sub-areas. Both summer and winter peaks are shown for the ten year study period. ISO-NE's load response programs are accounted for as a separate resource and so are not included in the load forecast.

33 This filing is FERC Form No. 715, which is an annual transmission planning and evaluation report submitted to FERC by the transmission companies each spring. It includes base case power flow data, with a summer and winter peak forecast.

Reference Forecast	Summer Peak Loads			Winter Peak Loads		
	2003	2012	CAGR*%	2003/04	2012/13	CAGR* %
NEPOOL	25121	28709	1.5	22011	25166	1.5
States						
CT	6915	7721	1.2	5928	6671	1.3
ME	1849	2098	1.4	1881	2114	1.3
MA	11498	13221	1.6	9907	11372	1.5
NH	2113	2533	2.0	1921	2302	2.0
RI	1734	1969	1.4	1348	1534	1.6
VT	1012	1163	1.6	1025	1180	1.6
Sub-areas						
BHE	312	350	1.3	360	392	1.0
ME	956	1091	1.5	986	1119	1.4
S-ME	533	604	1.4	538	606	1.3
NH	1617	1944	2.1	1532	1847	2.1
VT	1203	1403	1.7	1190	1375	1.6
BOSTON	5222	6133	1.8	4448	5215	1.8
CMA/NEMA	1635	1852	1.4	1388	1571	1.4
W-MA	1963	2148	1.0	1805	1987	1.1
SEMA	2550	2934	1.6	2101	2405	1.5
RI	2266	2587	1.5	1823	2076	1.5
CT	3350	3746	1.3	2952	3236	1.0
SWCT	2263	2518	1.2	1908	2273	2.0
NOR	1251	1400	1.3	981	1062	0.9

* Compound Annual Growth Rate
Source - RTEP 2003 Technical Report

Table 2 - NEPOOL, States, and RTEP Sub-area Peak Load Forecast Summary

The New England power system is a summer peaking system – that is, the highest demand for power during the year typically occurs during the summer season. As indicated in Table 2, the projected system peak demand for summer 2003 was 25,121 MW, while the projected winter peak demand for 2003 - 2004 is 22,011 MW. Typical spring and fall peak demand ranges from 17,000 MW to 19,000 MW. In August 2002, the region reached an all-time record demand of 25,348 MW. The all-time winter record demand of 22,727 MW was set on January 15, 2004.

ISO-NE expects load to continue to grow by 15 percent over the next ten years. Although anticipated growth rates differ from state to state and sub-area to sub-area, both summer and winter peaks are expected to grow at a compound annual rate of 1.5 percent per year over the next ten years. The forecasted system peak demands reflect estimated energy reductions from utility-sponsored demand-side management (energy conservation) and efficiency programs of 1,657 MW in 2003, growing to approximately 2,000 MW by 2012.

3. Resources

To meet the needs of New England electric customers, the New England grid calls on generation from power plants throughout the region. Energy produced by these plants is transmitted to customers over a complex network of electric transmission lines. The following sections describe these resources in more detail, describe the systems that protect electric equipment from damage, and outline the contribution that distributed generation may make to electric system reliability.

a. Generation

The current total installed generating capacity in New England is approximately 31,000 MW. Hydroelectric plants compose a relatively large proportion of the northern New England generation as compared to the south. Normal dispatch, considering both generation availability and transactions with neighboring systems, results in multiple intra-New England power transfers of varying direction, magnitude, and duration. The recent development of nearly 10,000 MW of new generation in New England could result in situations where generation not proximate to load cannot serve the load because of limited transmission capability.

Figure 4, below, shows 2002 NEPOOL historical energy generation by fuel type in gigawatt-hours ("GWH")[34] and percent. Roughly 56 percent of the energy generated in 2002 was from fossil-fueled units. Nuclear generation contributed approximately 26 percent of the total generation, while energy from hydropower and miscellaneous resources equaled approximately 11.5 percent. Net energy interchange with neighboring Control Areas accounted for approximately 7.5 percent of the total energy requirements.

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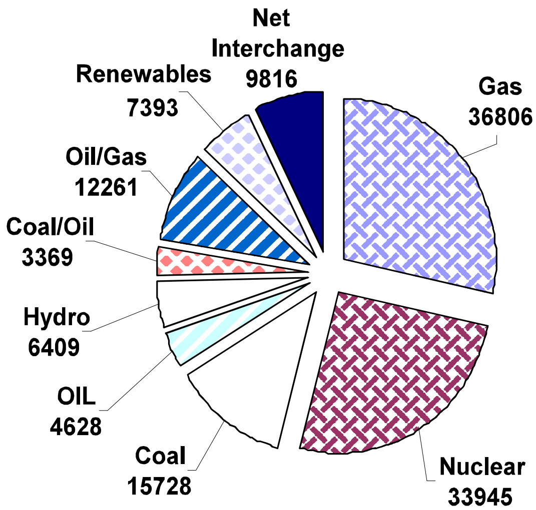
[34] One GWH equals one billion watthours.



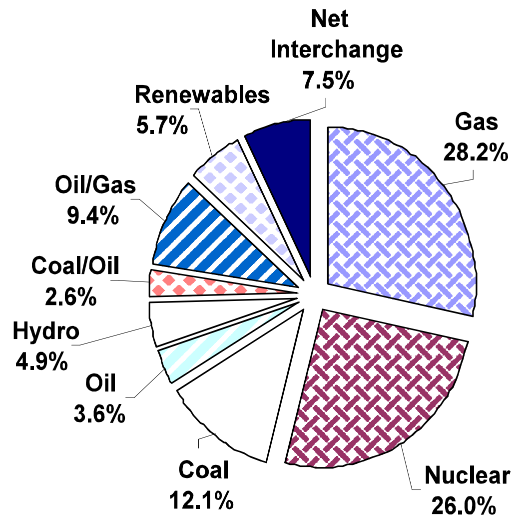


Figure 4 - 2002 NEPOOL Annual Source of Energy in GWH and Percent

Figure 5, below, shows NEPOOL installed capacity by fuel type. Fossil fueled units account for approximately 73 percent of installed capacity; these include natural gas-fueled units, accounting for approximately 38 percent of installed capacity, oil-fueled units, accounting for approximately 25.5 percent of installed capacity, and coal-fueled units, accounting for approximately nine percent of installed capacity.[35] Nuclear capacity represents approximately 14 percent of the total, while hydro capacity accounts for approximately 10.5 percent. The remaining three percent is renewable generation consisting of refuse, wood, wind and other renewable resources.

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[35] Winter ratings for installed capacity differ from summer ratings.

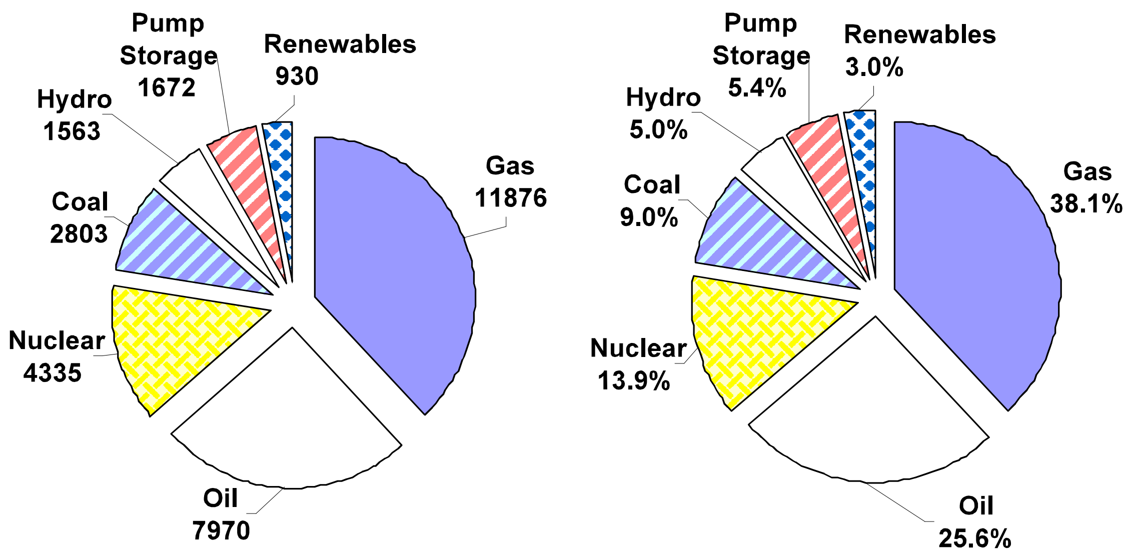

Figure 5 - NEPOOL Installed Capacity by Primary Fuel Type Summer 2003 (MW and Percent)

Figure 6, below, shows the generating unit additions in New England for each ten-year interval since 1904. As shown, more than 50 percent of the generating capacity was built prior to 1984. Approximately 9,000 MW of new generation has been added to the NEPOOL system during the past ten years - some 8,350 MW since the May 1, 1999 implementation of the NEPOOL Markets.[36] The median age of generators greater than five MW in New England is 27 years.

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36 According to ISO-NE, an additional 2,536 MW of generation has been reviewed and approved by the NEPOOL/ISO Reliability Committee. Of this, 521 MW is currently under construction. The NEPOOL/ISO Reliability Committee approval is based on the results of a transmission system impact study; the purpose of this study is to determine whether the proposed new facility will compromise the reliability of the system. Some or all of the 2,015 MW that has been approved but is not yet under construction may be abandoned by project developers.

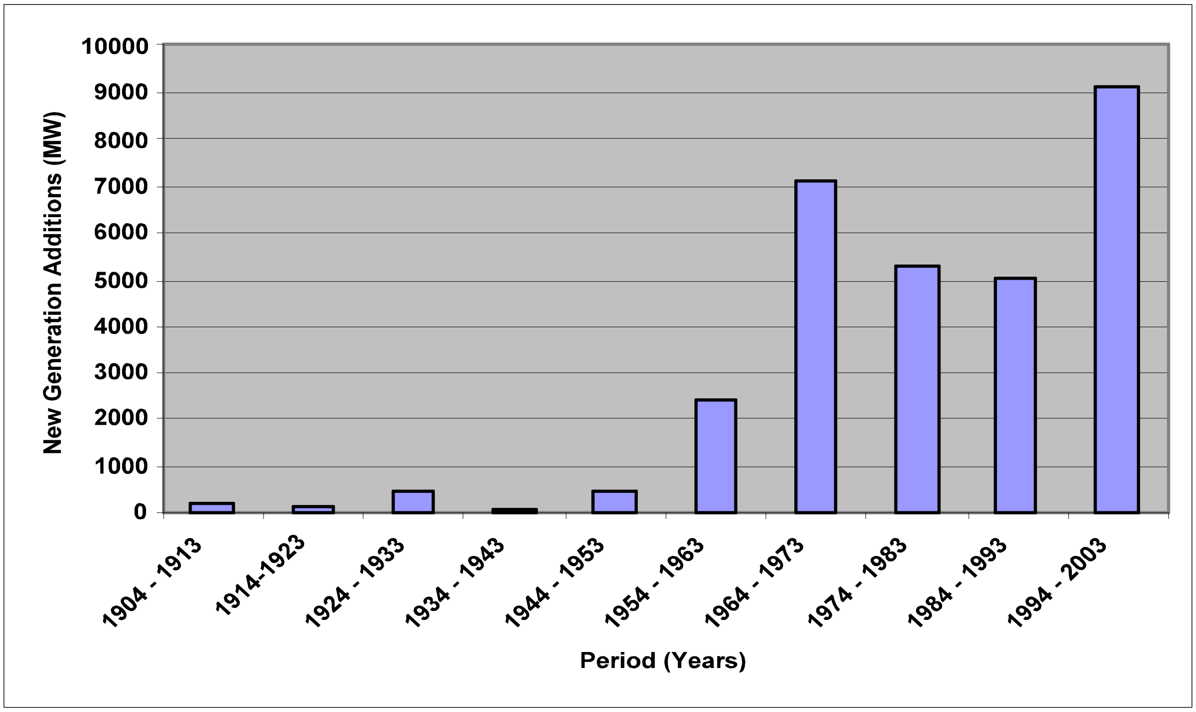

Figure 6 - Generating Unit Additions in New England (MW)

For comparison, Figure 7, below, illustrates the national mix of the generation resources. The average age of power plants in the United States is approximately 35 years.

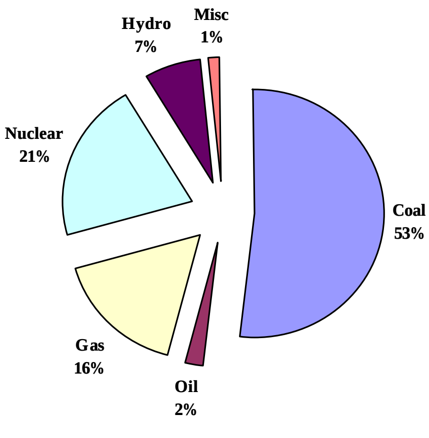

Figure 7 - United States Mix of Generation Resources

The generation mix in Massachusetts consists of: (1) natural gas-fired plants at about 47 percent; (2) oil-fired at about 20 percent; (3) hydroelectric at about 14 percent; (4) coal at about twelve percent; (5) nuclear at about five percent; and (6) waste-fueled and other renewable resources at about three percent. Massachusetts has a total installed summer capacity of approximately 13,500 MW.

The Boston RTEP sub-area has a higher percentage of power reliant on natural gas at about 70 percent, followed by oil at about 19 percent, coal at about eight percent, and waste-fueled and renewable resources at about three percent. The average age of the Massachusetts generators based on MW output is approximately 23 years. The average age of the Boston area generators based on MW output is approximately 21 years. Excluding the new Mystic Units 8 and 9, the average age is approximately 32 years.

The ages of generating units in the various RTEP sub-areas differ widely. Figure 8, below, illustrates the composite age of Massachusetts generation, including the Western Massachusetts ("WMA"), Southeastern Massachusetts/Rhode Island ("SEMA"), and greater Boston (including the North Shore) ("BOS") RTEP sub-areas.

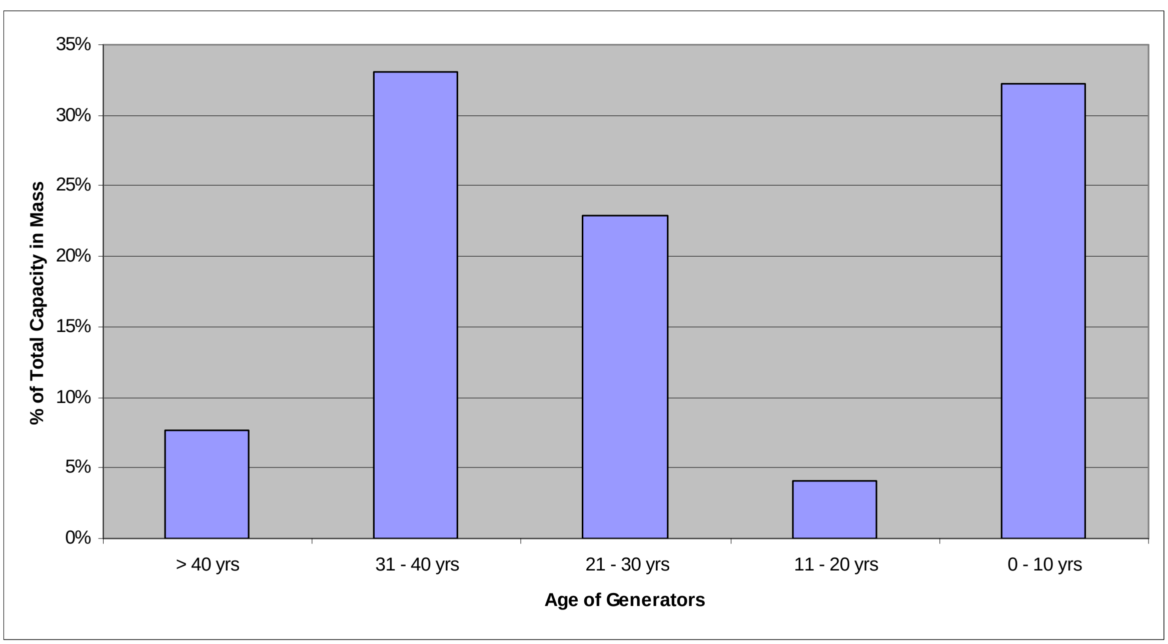

Figure 8 - Age of Generators in WMA, BOS, SEMA

In 2003, applications were submitted to ISO-NE proposing retirement of the following eight generating units located in eastern Massachusetts: (1) Mystic Station Units 4, 5 and 6 (oil-fired steam plants that began commercial operation in the late 1950's); (2) New Boston 1 (a gas-fired steam plant that began operation in the late 1950's as an oil-fired unit); (3) Salem Harbor Units 1, 2 and 3 (coal/oil-units built in the 1950s); and (4) Salem Harbor 4 (an oil-fired unit built in 1972).[37] Table 3, below, shows the capacity of these eight units.

	Summer Capacity (MW)	**Winter Capacity (MW)**	**Proposed Retirement Date**
Mystic 4	135	135	September 1, 2003
Mystic 5	135	135	September 1, 2003
Mystic 6	135	135	September 1, 2003
New Boston 1	370	370	December 31, 2003 or earlier
Salem Harbor 1	82	84	October 1, 2004
Salem Harbor 2	80	79	October 1, 2004
Salem Harbor 3	149	150	October 1, 2004
Salem Harbor 4	400	431	October 1, 2004
Total	1,486	1,519	

Table 3 - Capacity of Units Proposed for Retirement[38]

When a generating unit is proposed for retirement, ISO-NE undertakes a review to determine whether retirement of the unit would result in a "significant adverse effect upon the reliability or operating characteristics of its system or of the systems of one or more other Participants."[39] ISO-NE recently approved the retirement of Mystic Units 4, 5 and 6 as of

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37 New Boston Unit 2, a second 370 MW gas-fired steam plant, was retired in 2002.

38 Capacity is based on the applications for retirement. The current seasonal claimed capability may vary for some units.

39 Letter of Mr. Gordon van Welie to the DTE regarding "Inquiry Into the Application of USGen New England, Inc. for the Retirement of the Salem Harbor Electric Generating

(continued…)

December 15, 2003. ISO-NE has denied applications for the retirement of the New Boston and Salem Harbor units. ISO-NE expects to enter into a contract with the owners of Salem Harbor Station to ensure that the facility will be retired without adverse effect on system reliability. Exelon has filed with the FERC for an extension of the existing reliability must-run contract for New Boston 1. The terms of any such contracts must be approved by FERC.

b. Distributed Resources

Distributed resources consist of resources applied at the customer's location, a substation, or other load supply point in the system. Distributed resources are of two types: (1) demand response, including load response programs and energy efficiency initiatives; and (2) distributed generation ("DG"). In a demand response program, commercial and industrial electricity users can receive incentive payments if they reduce their electricity consumption or operate generation in response to high real-time wholesale electricity prices, or when reliability of the region's grid is stressed. DG is "a generation facility or renewable energy facility connected directly to distribution facilities or to retail customer facilities which alleviate or avoid transmission or distribution constraints or the installation of new transmission facilities or distribution facilities." G.L. c. 164, § 1.

i. Demand Response Programs

ISO-NE initiated a formal demand response program in 2001 to enhance participation of loads in competitive wholesale energy markets. The degree of participation in ISO-NE's demand response programs has grown from less than 100 MW in 2001 to almost 400 MW in 2003. The current ISO-NE demand response program is of two types: (1) programs intended to promote greater system reliability, and (2) programs intended to increase market participation by price responsive loads.[40] Additionally, a demand response working group has been established.

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39 (…continued)
Station, D.T.E. 03-51" (July 30, 2003).

40 Treatment of demand response programs is cursory. For more information see: http://www.iso-ne.com/Load_Response/main.html.

The reliability program participants are contacted during periods of capacity deficiencies pursuant to NEPOOL Operating Procedure No. 4 (“OP-4”).[41] When contacted, the participants must reduce their consumption within either 30 minutes or two hours of ISO-NE’s request depending on the program in which the customer is enrolled. Customers comply by either reducing load or operating on-site generation. The real-time price response program is triggered by a market price threshold and provides an economic incentive for customers to reduce their loads.

During 2002, the OP-4 action that would trigger the reliability program was not initiated. High system reliability during the peak loads made this action unnecessary. The real-time price response program was activated, however, and the average customer’s response rate was nine percent of the load enrolled. To encourage participation and improve performance, the 2003 load response program has been designed with more options and flexibility. In addition, ISO-NE participated in the New England Demand Response Initiative (“NEDRI”), a regional collaborative process. Recently, NEDRI has issued a report with many recommendations intended to enhance the effectiveness of demand response programs in the region.

ii. Energy Efficiency Programs

Electric companies and governmental decision-makers in New England have long understood that improvements in energy efficiency can provide multiple benefits to electricity customers, to the economy, to the electric grid, and to the region's environment. These benefits remain vital today, following restructuring, divestiture, and the evolution of regional wholesale markets. Substantial evidence indicates that significant market barriers to cost-effective energy efficiency investments remain, even in conditions of active wholesale competition, and that those investments could lower market clearing prices, improve reliability, and lower the region's total cost of electric service.

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[41] OP-4 procedures are initiated when (1) available resources are insufficient to meet anticipated load plus operating reserve requirements, (2) certain contingencies have occurred that result in an immediate deficiency of available required capacity resources; (3) transmission facilities in a sub area of the electric grid are loaded beyond established transfer capabilities, (4) a sub area of the electric grid is experiencing abnormal voltage and/or reactive conditions, (5) another system is experience a capacity deficiency which could reduce local operating reserves below required levels, and (6) there exists any other serious threat to the integrity of the bulk power system for which ISO-NE determines that OP-4 will mitigate the impact. Interruptible loads have been included as part of OP-4.

New England has been investing in energy efficiency as a cost-effective and valuable resource for more than a decade. States and utilities in New England have achieved net benefits (i.e., benefits exceeding costs) of about $3 billion dollars and peak load reductions of over 1,200 MW due to energy efficiency programs.

For example, one estimate from a 1999 report[42] that reviewed commercial and industrial programs administered by three utilities serving portions of New England concluded that the three utilities spent approximately $1 billion promoting energy efficiency within the business community to leverage almost $3 billion in energy savings through avoided electricity purchases over the lifetimes of the installed measures, resulting in net benefits (benefits minus costs) of $2 billion. New capacity needs were reduced by almost 1,000 MW. The resulting $2 billion in net benefits were achieved in the commercial and industrial (business) sector alone; savings and net benefits in the residential and low income sectors; savings since 1999, would be in addition to that amount.

In Massachusetts alone, in-state annual peak load reductions from both energy efficiency and system benefit charge ("SBC")[43] funded load management programs have ranged from 98 to 135 MW for 1998, 1999, and 2000. Total cumulative peak load reductions in Massachusetts from energy efficiency and load management were approximately 700 MW as of 2000, with energy efficiency accounting for over 90 percent of the reductions. For energy efficiency alone, annual incremental peak load reductions have been approximately 50 to 60 MW for 1998, 1999, and 2000. Without the 51 MW of energy efficiency summer peak load reductions in 2000, the summer peak would have been 0.6 percent higher in Massachusetts. The 2000 summer peak would have been 7.2 percent higher without the 648 MW of cumulative energy efficiency summer peak load reductions. This comparison is to the 1999 system peak, which was higher than the 2000 summer peak.[44]

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[42] A Decade of Progress with Business Energy Efficiency in New England, prepared by Boston Edison, the NEES Companies, and Northeast Utilities (July 1999).

[43] The SBC is a mandatory fixed charge per kilowatt hour ("KWH") to distribution company customers to fund energy efficiency activities, including, but not limited to, demand-side management activities. G.L. c. 25, § 19. The SBC for the calendar years 2002 through 2007 is 2.5 mills ($0.0025) per KWH. Id. All electric distribution company energy efficiency programs are funded solely from the systems benefit charge. Id.

[44] ISO-NE England RTEP03 Technical Report (November 13, 2003); Dimensions of Demand Response NEDRI final report (July 23, 2003).

iii. Distributed Generation

DG is a power plant that is sited close to sources of electrical demand and meet specific requirements of the particular demand. The distinguishing feature of DG is the connection to the grid at distribution voltage rather than at transmission voltage. The connection of DG at the distribution level limits the maximum size of the unit due to voltage variation limitations, reactive load supply requirements, and existing base load on the feeder. For example, typical DG on 15 kV distribution line would be limited to two to five MW, at a maximum.

DG consists of a variety of technologies that serve a number of roles throughout the region. The most common role for DG is that of emergency generators at large - critical facilities which can be dispatched when the electric power goes out at a given location. DG is also used for reducing or "shaving" peak load, providing critical base load power, emergency power, and/or combined heating/cooling and electricity at a single customer site. Very clean, developing new technologies show promise as potential economic alternatives to conventional grid power. These new DG technologies include microturbines and fuel cells.

In addition, DG can meet customers' energy needs and has potential for demand response. Further, because of its potential to reduce peak load, DG may relieve transmission and distribution constraints and help protect against outages. Widespread installation of DG, however, may raise safety and reliability concerns for distribution systems. In light of these benefits and concerns, the DTE has opened an inquiry into DG in Massachusetts.[45] This inquiry focuses upon: (1) the development of interconnection standards and practices that do not threaten the reliability or safety of existing distribution systems, but also do not present undue barriers to the installation of distributed generation; (2) the appropriate method for the calculation of standby or back-up rates and other charges associated with the installation of distributed generation; and (3) the appropriate role of distributed generation in distribution company resource planning.

c. Transmission Lines and Protection Systems

The New England transmission system is comprised mostly of 115 kV, 230 kV, and 345 kV circuits. Three 345 kV lines provide the major transmission links between eastern and western New England. Transmission lines in the north are generally longer and fewer in number than in the south. The increased transmission density in the south reflects larger load and power supply concentrations.

NEPOOL is interconnected with New York through two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, and one 69 kV tie. Currently, NEPOOL and New

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[45] Distributed Generation, D.T.E. 02-38 (2002).

Brunswick are connected through one 345 kV tie, with a second 345 kV tie planned. There are also two HVDC interconnections with Quebec: (1) a 225 MW back-to-back converter at Highgate in northern Vermont; and (2) a +/- 450 kV DC line. The terminal configurations of the latter allow non-simultaneous operation of either a 690 MW connection at Comerford in northern New Hampshire, or a 2,000 MW connection at Sandy Pond in eastern Massachusetts.

Major transmission and generation equipment are protected from damage by automatic devices called protective relay systems. Protective relay systems are designed to maintain a high degree of dependability and security to keep the power system stable and reliable. Protection schemes provide service continuity and limit damage by promptly removing faulted equipment from service. System stability and reliability are maintained by removing only the faulted equipment from service and by removing faults quickly.

Protective relaying is one part of a system that allows for the normal operation of the power system and provides for the protection of the associated power system equipment during abnormal or fault conditions. A protective relay system is typically comprised of sensing equipment such as current and voltage transformers, protective relays, auxiliary relays, circuit breakers, and, in some limited applications, motorized disconnect switches. This equipment is assembled to provide maximum protection of the power grid by quickly sensing and isolating faults on the system.

The power system is divided into protected areas or zones. The protection schemes are designed to overlap these zones to avoid having an unprotected area. The primary purpose of these zones is to ensure that only the affected equipment is removed from service.

A protective relay system typically consists of a primary system and a secondary (or backup) system. In bulk power transmission substations, two independent protection systems are maintained to ensure high speed clearing of faults. For lines that are part of the bulk transmission system, both relay systems will usually have communication equipment to provide accelerated tripping to clear faults in the protected zone. Two protective relay systems are used to reduce the risk of clearing faults slowly due to a relay system failure. The function of protective relays varies from measuring a single quantity such as current, voltage, or frequency, to sensing two quantities for more complex protection. Relays that measure a single quantity are designed to operate when values rise above or go below the relay set point. For example, with overcurrent protection, the relay will not operate during normal conditions. However, when the current on the line increases during a fault, the overcurrent relay senses this increase and will operate to clear the fault in the protected zone.

Transmission relays typically are more complex, combining voltage and current sensing, and measuring apparent impedance. The directional distance relay is the most common protection application for transmission lines on the power system. When a fault occurs, the resulting increase in current and decrease in voltage causes the relay to sense a decrease in apparent impedance. The distance relay relies on the lower apparent impedance of a fault, as compared with normal loading, to detect and clear faults in the protected zone. Total clearing time at both ends of the line can be accelerated through introduction of communication-aided tripping, whereby a relay located at one end of the protected line can signal the remote relay to accelerate the clearing of faults. Two of the communication aided protection schemes in use with distance relays are known as directional comparison blocking ("DCB"), and permissive overreaching transfer trip ("POTT").

Other applications of protective relaying, apart from transmission line protection, include generator protection, transformer protection, capacitor bank protection, reactor protection, and bus protection. Many of the same principles used to protect transmission lines are also used to protect these elements.

Underfrequency protection is used to maintain system integrity when a partial but substantial loss of generation occurs. If significant generation capacity is lost, the system load will be in excess of remaining generation capacity. The remaining generation will attempt to maintain the load. As a result, the frequency will decline at a rate proportional to the deficiency. Unless arrested, the decline of frequency may have an adverse effect on generators and other equipment on the power system. In order to survive a significant loss of generation, it is necessary to automatically shed load to restore balance between the load and the remaining generation. The function of the underfrequency relays is to detect such an event and initiate automatic load shedding. If balance between generation and load cannot be achieved, the system may shut down and equipment may be damaged which would slow any restoration efforts. As this is occurring, the resultant heavy power flows through portions of the system may cause the directional distance protection on portions of the transmission system to operate as the apparent impedance travels through the relay's operating zone. This is the condition that occurred on August 14th; most of New England was disconnected from New York which had the effect of maintaining the system in an operating state.

In addition to automatic load shedding there are two manually actuated schemes available to system operators: (1) voltage reduction, and (2) manual load shedding. Voltage reduction reduces the voltage on selected distribution feeders by five percent to reduce load demand. Manual load shedding is designed to remove blocks of distribution feeders from service in a predetermined hierarchy. Both manual schemes are designed to reduce the load demand on the power system if it is near or over capacity with no additional generation immediately available. These schemes are initiated by the system control operator via the Emergency Management System ("EMS").

Special protection systems ("SPS") may also be used to address overload conditions resulting in a mismatch between generation and load. Power flows on a portion of the transmission system may become excessive when available transmission limits the paths available to move power between areas. SPS are intended to recognize or anticipate such a condition and operate in a secure and dependable manner to reestablish operation within equipment limits.

B. System Operations, Maintenance and Planning

1. System Operations

ISO-NE is the control area operator and reliability coordinator responsible for the day-to-day reliable operation of the bulk electric generation and transmission system in New England. The ISO-NE operates the system according to NEPOOL, NPCC and NERC requirements for a reliable electric system. Operation of the electric power system in New England is implemented through a hierarchical structure called the master/satellite control configuration. ISO-NE is the master control center for New England and oversees and coordinates operations with four satellite control centers: Maine, New Hampshire, CONVEX (which operates Connecticut and parts of western Massachusetts) and REMVEC (which operates Rhode Island, eastern Massachusetts, Vermont, and parts of western Massachusetts).

ISO-NE also coordinates operations with the neighboring regions of New York, Quebec, and New Brunswick, and all generators in New England. ISO-NE and the satellites operate the bulk electric power system according to control area-specific reliability standards (NEPOOL Operating Procedures), regional standards (NPCC criteria, guidelines and procedures), and standards for North America (NERC policies).

ISO-NE and the satellites continuously assess system conditions and can implement a variety of actions to maintain or restore transmission reliability to normal conditions including: deviation from economic dispatch; arming special protection systems or setting up pre-planned opening of circuits; using weather-sensitive transmission facility ratings; switching transmission circuits; or implementing a series of predetermined operating procedures.

Training for ISO-NE operators is conducted through the ISO-NE's Operations Training Department. Training is extensive and ongoing, including classroom, on-shift and software-based training, as well as use of the Training and Testing Simulated Environment Simulator. IS-NE operators are required to be certified by the NERC. The NERC examination measures a system operator's knowledge of NERC operating policies and basic principles of interconnected operation. ISO-NE offers annual training for new and existing operators on NERC certification and recertification. Most of the satellite operators also hold NERC certification. NERC requires that system operators be trained on normal and emergency operating conditions, disturbances, and other unusual occurrences in the power system.

2. Operational Reliability Criteria

The development of general reliability criteria is coordinated by NERC, with the participation of members from the electric power industry. These general criteria are described in nine NERC policies. The regional reliability councils establish region-specific criteria consistent with the NERC policies. The criteria, guidelines, and procedures developed and maintained by NPCC contain the region-specific interpretation of NERC policies. NERC criteria, designated as type “A” documents, describe the minimum criteria applicable to NPCC members. NPCC guidelines assist the implementation of NERC criteria. NPCC procedures provide for uniform implementation, interpretation, and monitoring of conformance with NERC criteria and guidelines. NERC’s current authority is limited to monitoring compliance with its policies.

The foundation for NPCC documents is document A-2 (Basic Criteria for Design and Operation of Interconnected Power Systems), which sets forth, in a single set of criteria, the principles of interconnected planning and operations. The NERC policies describe operation of the interconnected power system in terms of control areas and reliability coordinators. Control areas maintain a balance between energy supply, demand, and interchange. Reliability coordinators coordinate transmission analysis, operation, and maintenance. ISO-NE operates the New England control area and is the reliability coordinator for the region.

NERC policies, NPCC criteria and NEPOOL Operating Procedures are interrelated. For example, in conformance with NERC and NPCC criteria, ISO-NE and satellites use NEPOOL OP-19 (Transmission Operations) to operate the New England bulk power transmission system, which includes lines rated at 69 kV and above. OP-19 requires the transmission system to be operated so that the most severe single contingency will not cause (1) equipment damage due to thermal overload, (2) cascading thermal overloads, (3) excessively high or low voltage or voltage collapse, (4) unit or area instability, (5) undamped oscillations, (6) loss of other critical facilities or portions of the bulk power system, or (7) violation of neighboring areas' operating reliability criteria.

There are two levels of transmission reliability: normal conditions and emergency conditions. Under normal conditions, the system is non-stressed and operating at a higher level of reliability. ISO-NE operates the system to normal conditions, which includes first and second contingency protection (i.e., maintaining adequate reserves to be able to recover from the loss of the largest single resource on the system in ten minutes and from the loss of one half of the second largest resource in 30 minutes).

The system is in an emergency condition if normal criteria are violated. When the system is in an emergency condition, ISO-NE implements emergency actions, as necessary, in order to restore the system to normal conditions within 30 minutes. Emergency actions may include opening or closing transmission circuits to relieve transmission constraints, implementing OP-4 Actions 12 through 15 (which include voltage reductions and public appeals for conservation), and implementing NEPOOL OP-7 (Action in an Emergency) (which includes load shedding).

In certain circumstances, emergency actions must be taken before a contingency event occurs. In addition, OP-19 provides protection for certain inter-area impacts (i.e., impacts beyond the New England control area, which are unacceptable). These include contingencies that can threaten large areas within New England by splitting away from the bulk power system due to cascading thermal overloads, voltage collapse or instability, and any contingency internal to New England that would have a worse impact on an external area than that area's most severe contingency.

NERC, NPCC and NEPOOL requirements for reliability are also interrelated. For example, with respect to load shedding:

1. NERC Policy 5 (Emergency Operations) requires each control area to take prompt and appropriate action to relieve any abnormal conditions that could jeopardize reliable interconnection operation. This policy requires each control area to establish a plan for manual and automatic load shedding to arrest frequency or voltage decays that could result in an uncontrolled failure of the interconnection;

2. NPCC Emergency Operation Criteria (Document A-3) requires each control area to be capable of manually shedding at least 50 percent of its load in ten minutes or less;

3. NEPOOL OP-7 establishes procedures for action by the ISO-NE in the event of an operating emergency including load shedding. OP-7 specifies that the "ISO has the responsibility and authority, in accordance with NERC, NPCC and NEPOOL policy, to direct the actions that may be required for the implementation of this Procedure, such as load shedding or opening of circuits, when the emergency situation involves: (1) an overall capacity or energy deficiency in New England or in any area within New England; (2) New England's interconnections with adjacent Control Areas/systems; (3) conditions on facilities external to New England caused by operations or conditions within the New England Control Area; (4) transmission and/or generating facilities within New England; or (5) any other emergency conditions where the ISO deems it appropriate;" and

4. NEPOOL OP-19 establishes procedures for action by the ISO-NE during normal and emergency conditions and for post-contingency operation.

With respect to stability assessment:

1. NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) specifies that the "stability of the bulk power system shall be maintained during and following the most severe contingencies including a permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing;" and

2. NEPOOL OP-19 requires protection for a variety of normal contingencies including, "a permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing."

3. Electric System Operation and Maintenance Practices

a. Transmission and Distribution Maintenance Practices

The purpose of transmission and distribution ("T&D") equipment is to provide the delivery medium to get electric energy from the generators to the consumers. In order to accomplish this purpose, the equipment must be maintained in a regular, diligent, and timely manner to ensure proper working condition and operation. Proper operation of T&D equipment allows the utilities to maintain the safety of its employees and the public, to protect T&D equipment from damage, and to minimize the disruption of service to customers. In some cases, this equipment prevents service interruptions through automatic protection schemes and automatic alternate feeds. Finally, metering systems provide data that allow analysis of system conditions which helps determine operational improvements to maintain reliability for customer benefit.

The T&D systems that most utilities maintain include:

1. Underground Structures. Underground vaults and manholes are periodically inspected, as is the underground equipment, including network transformers, protectors and switches;

2. Overhead Lines. Overhead T&D systems are patrolled regularly for safety, pole and hardware condition, and circuitry. These visual inspections are performed by walking, driving or flying;

3. Power Poles and Structures. Intrusive pole testing and maintenance/ treatment for both transmission and distribution poles and structures; and

4. Substations. Substations are visually inspected and maintained on a frequent basis. In addition, equipment internal to the substation is

monitored and alarmed via remote control centers, as well as inspected, tested and maintained on a regular basis.

Electric companies regularly inspect, test, and maintain their T&D equipment in a proactive manner. There are three types of maintenance performed: predictive, preventative and corrective. Predictive maintenance uses the number of cycles or operations of a device to define the optimal time to maintain equipment. Preventative maintenance is performed through a series of inspections. These inspections may note some condition that, if not remedied, could lead to mis-operation or failure. The final type of maintenance is corrective maintenance. This can be initiated through several means, including inspection, monitoring operational parameters, and equipment mis-operation or failure. This reactive approach is used when external forces damage equipment and/or equipment failures occur.

The types of inspections and testing for transmission equipment typically include:

1. Overhead aerial patrols of transmission lines for damaged equipment;

2. Aerial infrared patrols of transmission lines for hotspot conditions of conductors, connectors, lightning arrestors, and bushings;

3. Foot patrols of transmission lines for damaged equipment;

4. Pole and tower inspections for structural integrity;

5. Diagnostic inspections for sulfur hexaflouride (“SF_6”) gas leaks; and

6. Underground transmission line cathodic protection and electrolysis surveying; periodic testing of emergency pressurization equipment; pump plant inspections; oil and dissolved gas analysis of pipe cable oil; and road, bridge and railroad crossing inspections.

The types of inspections for T&D substations and distribution lines typically include:

1. Substation transformer condition assessment;

2. Substation transformer current and voltage monitoring;

3. Substation transformer and load tap changer (“LTC”) oil level and color;

4. Substation transformer secondary winding temperature;

5. Substation battery conditions;

6. Patrols of distribution backbone conductors and connected equipment to assess overall condition and status of vegetation management;

7. Distribution circuit current and voltage monitoring;

8. Infrared and visual monitoring of overhead conductors and equipment (including large customer transformers) for hotspots or signs of overheating; and

9. Inspections of poles solely owned by electric companies and electric maintenance areas.[46]

The types of testing for other T&D equipment typically include:

1. Dissolved gas analysis testing performed on substation transformers, LTC compartments, selector compartments, and regulators. The test determines the internal condition of this equipment and facilitates early intervention and repair of internal problems. The testing may be performed on distribution transformers as well;

2. Electrical insulation testing of substation transformer and breaker oil filled bushings and underground transmission pipe cable;

3. Travel/timing testing of substation T&D circuit breakers;

4. Relay testing of critical substations and lines based on NPCC and individual guidelines;

5. Protective relay trip testing;

6. Thermal imaging scans;

7. SF_6 leak detection and moisture content, purity, and arc by-product testing;

8. Breaker mechanism inspection to thoroughly overhaul the operating mechanism of the circuit breaker. This test assures proper and reliable operating performance of circuit breakers;

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[46] Electric distribution company and telephone joint ownership pole agreements define maintenance areas and responsibilities for pole setting, maintenance and replacement.

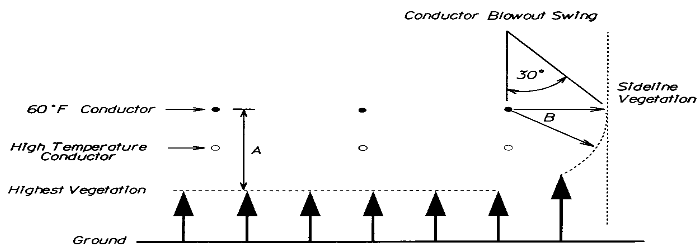
9. Ductor or contact resistance test performed based on the number of fault operations experienced by a breaker since its last maintenance or if the oil dielectric test or the SF_6 gas tests indicate anomalous results;

10. Oil dielectric tests where oil samples are obtained from oil-filled equipment in accordance with the frequency of inspection and maintenance in service manuals. This test establishes the condition of oil-filled equipment and helps determine the degradation of insulation mediums; and

11. Cable testing, performed as needed, to determine the condition of underground cable insulation resistance. Utilities perform these tests on underground cables when there is a pattern of failure with a specific type of cable or specific method of installation. Field testing includes: (a) high potential testing, which tests cable insulation and components; (b) concentric neutral tests, which assess the connectivity of neutrals; and (c) partial discharge, which tests the integrity of cable insulation. The scope, type, and frequency of this maintenance are defined by the individual utility's assessment of equipment condition and need.

Electric company maintenance practices also include vegetation management programs. As part of such programs, companies undertake proactive tree-trimming programs which involve the inspection and maintenance of distribution lines, transmission lines, and T&D rights-of-way on a regular rotating basis, or more often if problem areas arise. The yearly operational plans and right-of-way cycles are submitted to the DTE. Utilities also make limited use of herbicides in compliance with applicable local, state, and federal regulations. NEPOOL has established vegetation management standards for transmission rights-of-way, which are illustrated in Figure 9, below.

STANDARD CLEARANCE BETWEEN CONDUCTOR AND VEGETATION



Line Voltage	A (feet)	B (feet) 500 ft. span	B (feet) 750 ft. span	B (feet) 1000 ft. span
69/115kV	11	14	20	29
230kV	13	18	26	36
345kV	15	22	30	43

Footnotes:

A Vertical clearance of 6, 8 and 10 feet for 69/115, 230 and 345kV, respectively, plus sag of 5 feet during high temperature operations.

B Horizontal clearance of 6, 8 and 10 feet for 69/115, 230 and 345kV, respectively, plus 30 degree blowout at span lengths shown, and 6 pounds per square foot wind at 60 degree F.

A & B In certain circumstances where above assumptions do not apply, more or less clearance may be required to meet the clearance of 6, 8 and 10 feet for 69/115, 230 and 345kV, respectively.

Figure 9 - Excerpts from NEPOOL OP-3 (Right-of-Way Vegetation Management Standard)

b. Generator Operation and Maintenance Practices

The operation and maintenance of generation equipment requires the exercise of reasoning, including sound engineering and economic judgment. Power plant operators have developed operation and maintenance procedures that dictate the means for managing their assets. These procedures apply the pertinent codes, standards, guidelines, generally accepted industry practices, and equipment manufacturer's recommendations to ensure optimal performance, reliability, and safety. Although all generators generally apply similar standards and guidelines, specific operating and maintenance practices are highly dependent upon the design, age, and operation mode of the generator.

Generator design varies significantly by energy source, with each generator design requiring a different set of operation and maintenance procedures. The operation and maintenance of equipment also varies with the age of the generator. An older generator will require more maintenance and replacement parts than a newer generator. Certain components require full replacement after about 20 years of service. In addition, a generator that operates at a constant output, such as a base-load power plant, will be considered a plant with less age and wear-and-tear than one that operates solely during peak periods.

As Table 4, below, shows, New England's generation mix includes a range of resource types, and a range of older and younger generators. Each generator type has its own maintenance standards, patterns, and practices.

Summer Capacity Mix of Power Plants			
	New England	**Massachusetts**	**Boston-Area**
Natural Gas	38 percent	47 percent	70 percent
Oil	26 percent	20 percent	19 percent
Nuclear	14 percent	5 percent	0 percent
Hydroelectric	10 percent	14 percent	0 percent
Coal	9 percent	12 percent	8 percent
Renewable	3 percent	3 percent	3 percent
Total Capacity	31,000 MW	13,500 MW	3,900 MW
Average Age of Plants	27 years	23 years	21 years

Table 4 - Summer Capacity Mix of Power Plants

The nuclear power industry, for example, has a set of maintenance standards developed over the years by the industry and the Nuclear Regulatory Commission ("NRC"). The maintenance procedures are expected to be rigidly performed, documented, and enforced. Most major overhaul and preventative maintenance is performed during planned outages for fuel replacement; these occur once every year and a half, typically during the spring or fall during periods of non-peak demand.

The operators of combined cycle[47] facilities typically have long-term service agreements with combustion turbine manufacturers that dictate specific maintenance and inspection practices based upon generating unit service hours and number of starts and stops.

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47 A combined-cycle generating unit is a combination of a steam turbine and one or more gas turbines, while a single-cycle combustion unit typically is a regular gas turbine. A steam turbine being part of a combined-cycle unit uses heat exhaust of a gas turbine to generate electricity; this energy is wasted in a single-cycle unit.

Combustion turbine maintenance for simple-cycle facilities, which operate only for a few hours a year at peak times, can be performed less regularly and only prior to the peak season.

The boilers, heat recovery steam generators, turbine generators, and other major equipment used in fossil fuel power plants also are operated and maintained in accordance with their design limitations and equipment manufacturers' guidelines. Industry groups meet on a regular basis to refine operation and maintenance practices in order to obtain better efficiencies and to enhance reliability.

Major preventative maintenance of boilers and other heat recovery equipment usually is performed once a year during a planned outage in the spring or fall. If the equipment is older, or if it operates in a peaking mode, major maintenance may be more frequent (two or three times a year). Steam turbines and electrical generators require less frequent major maintenance overhauls; major maintenance on this type of equipment typically is performed once every five years during a planned outage.

Hydroelectric and pumped storage facilities have less equipment in a less aggressive environment than many of the power plants discussed above and therefore require less maintenance. Typically, these units go through a scheduled shutdown and major overhaul once every five to ten years.

Maintaining or having access to a spare parts inventory is also a key factor in operating a reliable and high-availability power plant. Many power plants with the same owners/operators share spare parts or purchase them from other power plants nearby.

On-line maintenance functions are just as important as those performed during a maintenance outage. Proper on-line maintenance, which may include lubrication, seal and packing replacement, and repair of any component that has a redundant operating spare, adds to unit reliability and minimizes downtime.

In order to limit the number of simultaneous maintenance outages, NEPOOL requires generator owners and operators to submit schedules for any planned outages to ISO-NE and the appropriate satellite operator (REMVEC for eastern Massachusetts or CONVEX for western Massachusetts) in advance of the outage start date.[48] To the extent practicable, generator owners and operators are required to work with the satellites to select mutually agreeable dates for scheduled outages. ISO-NE may withhold approval for a planned outage if the outage

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[48] See NEPOOL OP-5 (Generation Maintenance and Outage Scheduling).

would result in a serious reliability risk (for example, implementation of NEPOOL OP-4 at Action 10 or higher[49] or implementation of NEPOOL OP-7 (Action in an Emergency)).[50]

4. System Planning

Because the New England electric system operates as an interconnected grid, system planning also is undertaken on an integrated basis. Within the context of the New England interconnected system, the ISO-NE coordinates the activities of a regional system planning process.[51] The ISO-NE coordinates the regional system planning process with the advice of the Transmission Expansion Advisory Committee ("TEAC").[52] A central component of the New England regional system planning model is the RTEP, a comprehensive electrical engineering assessment consisting of studies and analysis of the interconnected New England electric system.[53] The RTEP process identifies interconnected system reliability concerns. In addition, the RTEP process provides information to market participants regarding opportunities for investment to address the identified system needs. The RTEP process results in a detailed transmission plan that identifies projects for ensuring interconnected system reliability. The

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[49] NEPOOL OP-4 (Action During A Capacity Deficiency) has 16 actions, which when implemented include: running power generation facilities at their maximum levels; curtailing dispatchable load; requesting voluntary load curtailment at electric company offices; running non-contracted customers' power generation facilities at their maximum levels; allowing operating reserves to go to zero; purchasing emergency power from neighboring regions up to their maximum transfer capability; requesting voluntary load curtailment by all customers; and implementing five percent voltage reductions. Action 10 covers the first four of the above-mentioned items and also provides for an initial depletion of the 30-minute operating reserve. A "Power Watch" advisory is also issued by ISO-NE to the public.

[50] OP-7 establishes procedures to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, or unacceptable voltage levels in an isolated or widespread area of New England. These procedures were effectively declared during the August 14th blackout event to prevent instability and equipment overload in the Springfield and Pittsfield areas.

[51] The regional system planning model is included in the proposal to create a RTO for the New England interconnected system.

[52] The TEAC meets regularly throughout the year in the development of the RTEP.

[53] The RTEP process includes advisory committee meetings which are open to interested parties and a public meeting at which interested parties may comment to the ISO-NE Board of Directors.

most recent regional planning report, issued on November 13, 2003, and referred to as RTEP03, is included in this report as Appendix B. The following diagram illustrates the steps involved in the RTEP process.

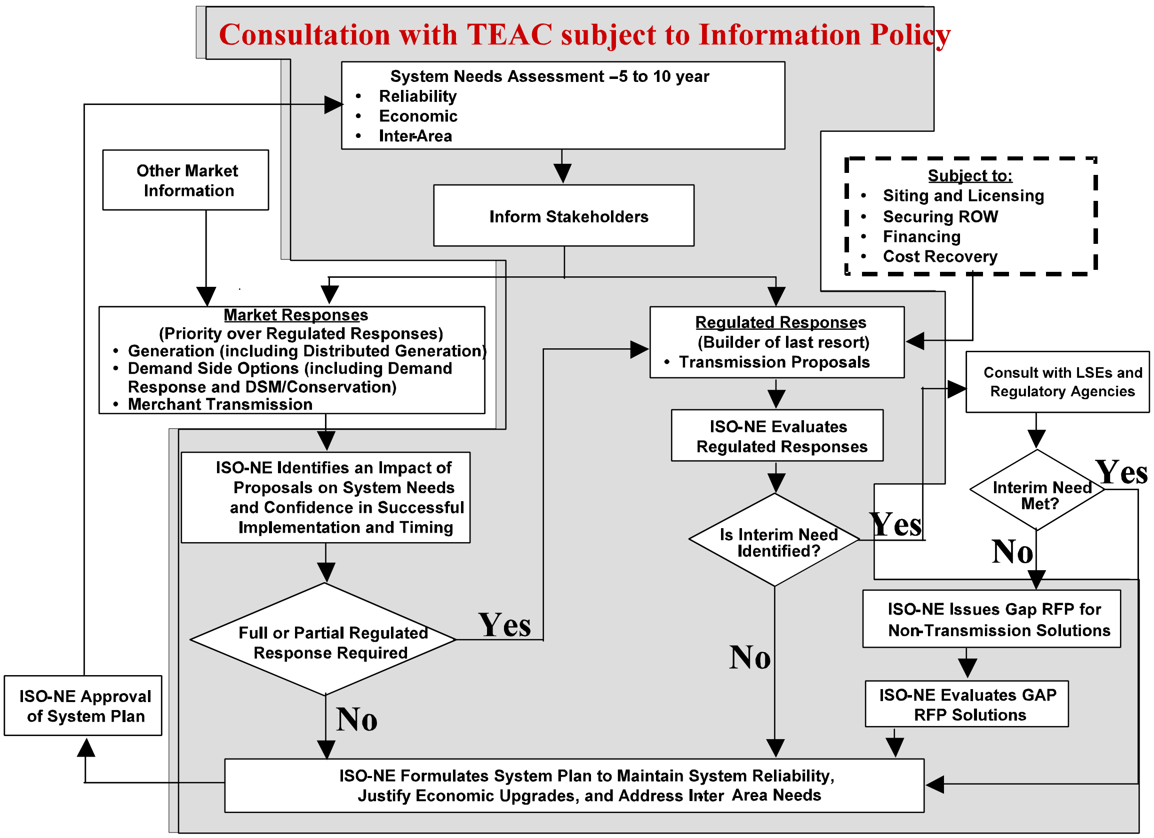

Figure 10 - RTEP Process Flow

The information from the New England RTEP process is coordinated with expansion plans of the interregional electric system, including New York, PJM, Quebec, Ontario, and the Canadian Maritimes through interregional planning agreements,[54] and by the NPCC through the annual NERC Reliability Assessment. The NERC Reliability Assessment provides information about reliability concerns within the interregional control areas, including: an assessment of the long-term electric supply and demand and transmission reliability; a discussion of key issues affecting reliability of electric supply and transmission reliability; and

54 The interregional planning agreements include the development of interregional planning process protocols.

regional assessments of electric supply reliability identifying areas of specific regional concern. The NERC 2003-2012 Reliability Assessment is included as Appendix C.

C. Reliability Assessment and Recommendations

1. Introduction

In earlier sections of this report, the Task Force has reviewed the causes of the August 14^{th} outage and has provided an overview of the design and operation of the New England electric system. With this information as background, and within the scope of this investigation, the Task Force now provides (1) its assessment of the vulnerability of the Massachusetts electric grid to a large-scale outage, and (2) consequent recommendations for reducing the probability of such an outage. In making this assessment, the Task Force looks first at the electric infrastructure in Massachusetts, next at events that could, in theory, lead to a large-scale outage, and finally at the ability of system operators to respond to unexpected events and minimize or prevent outages.

2. Electric Infrastructure in Massachusetts

As discussed in Section III.A, above, Massachusetts is part of an integrated electric system that covers the entire New England region. ISO-NE continually dispatches the system, and also coordinates transmission system planning for the region. ISO-NE also is responsible for assessing the reliability of various electric regions and sub-regions within the New England area.

The Task Force concludes that the electric infrastructure serving Massachusetts overall currently meets reliability standards, although there are reliability concerns for certain areas. However, both electric demand and the size and nature of the resources available to meet that demand will change over time. In order to ensure a reliable energy supply for its citizens, the Commonwealth must monitor developments in these areas. The Task Force, therefore, recommends that:

- Massachusetts should participate actively in ongoing regional transmission planning activities and monitor the resolution of reliability issues identified through these activities.

According to the most recent RTEP report, the NEMA/Boston area has both near- and long-term reliability concerns. Recently completed transmission upgrades, coupled with new generating units in service in the Boston area, have been very effective in mitigating current reliability and economic congestion concerns. However, there are three factors that will compromise the reliability of electric service in this area. First, the electric load in the downtown Boston and North Shore areas presently use all resources, both generation and transmission, available to serve it. Second, load in the area is expected to continue to grow. Third, ISO-NE has received applications to retire nearly 1,500 MW of generation in the NEMA/Boston area.

Two Massachusetts electric companies, NSTAR and National Grid, are developing transmission planning studies to address these concerns. Completion of the current studies will be accomplished and coordinated with the TEAC as soon as possible, with the goal of formulating transmission expansion plans to address emerging reliability issues.

These reliability needs could be addressed in a number of ways such as load conservation, transmission upgrades, and the development of new generation including DG. No plans are actively being pursued to add central or distributed generation in this area because of market conditions in New England. Currently planned load conservation, by itself, will not address these reliability issues. Transmission upgrades designed to bring energy from existing generation resources into the NEMA/Boston area may be key to providing reliable electric service to this area. Massachusetts electric distribution companies, working with ISO-NE through the RTEP process, are also developing transmission projects (including both new transmission lines and upgrades to existing facilities) to address these reliability needs. In order to ensure a reliable energy supply for its citizens, the Commonwealth must monitor developments in these areas. The Task Force, therefore, recommends that:

- Massachusetts should closely monitor the resolution of emerging reliability issues in Northeastern Massachusetts, particularly Boston.

The Task Force notes that the construction of new transmission may prove to be an appropriate solution to certain developing reliability issues. The design, siting and construction of new transmission facilities can be a difficult task, due to the nature of the facilities, the complexity of state and local permitting, and the number of interests that may be affected. While the Massachusetts Legislature reviewed and streamlined the generation siting process as part of the Electric Restructuring Act, there has been no similar review of the transmission siting process. The Task Force, therefore, recommends that:

- The DTE, Siting Board, and other interested parties should review all phases of the transmission siting process to determine whether it can be streamlined while protecting the integrity of the public review process and the interests of ratepayers, abutters, other affected parties, and the environment.

Major transmission and generation projects may be needed to address certain near-term reliability issues in Massachusetts. However, the Task Force believes that targeted investments in conservation, energy efficiency, and DG also may contribute to a more stable electric system. Further, investments in renewable resources may advance the goal of a diverse generation base. The Task Force, therefore, recommends that:

- Massachusetts should explore opportunities to create, through state and regional policy formulation and implementation, as well as system oversight, a more stable, more reliable electric system through investments in conservation, energy efficiency and DG. Where institutional or regulatory barriers inhibit such investments, Massachusetts should seek to eliminate these barriers while protecting the interests of the ratepayers.

- Massachusetts should continue policies that encourage the development of renewable resources in order to advance the goal of a diverse generation base.

3. Potential for Outages in Massachusetts

It is axiomatic that, regardless of the level of reliability built into the regional electric system, the potential for a large-scale outage cannot be totally eliminated. It is possible that an event, or a series of events, could place the system under stresses that it was not designed to handle, leading to system instability and possible outages. The Task Force has identified three situations where this might occur: (1) single events that result in multiple contingencies; (2) unrelated events that affect service in the same area; and (3) external events.

In electric system planning terms, a "contingency" is the loss of a single major system element (e.g., a transmission line or a generating unit). In New England, system operators are required to manage the electric system so that it will remain stable following the loss of any major system element. However, it is possible for a single event to cause the simultaneous loss of multiple system elements. For example, a fire at a centrally located substation could cause the loss of multiple transmission lines or generating units connected through that substation. A single event typically could cause multiple contingencies only where there is a concentration of infrastructure in one location. Southern New England, in general, and Massachusetts, in particular, present a concentration of electric system infrastructure. In some cases, the concentration of infrastructure serves an important purpose and cannot readily be avoided. In other cases, concentration of infrastructure may result from a desire to use already-developed rights-of-way or sites to ease permitting or limit the environmental impacts of new infrastructure. The Task Force, therefore, recommends that:

- Massachusetts, in coordination with ISO-NE and Massachusetts electric companies, should continue to review locations where a concentration of infrastructure creates a significant reliability risk and make practical recommendations for reducing the risk of disruption at those locations.

Multiple contingencies also may arise when unrelated events affect related electric infrastructure. The December 1, 2003 outage on Cape Cod would appear to be a case in point. During the course of the day, one of the two Canal generating units was out of service due to a steam leak, a 345 kV transmission line serving Cape Cod was taken out of service due to a fire on the right-of-way, and a fire affected operation of the second Canal generating unit. This combination of events resulted in the loss of approximately 300,000 customers representing almost 600 MW of load.

As the events of August 14th made clear, electrical events that originate outside Massachusetts (and outside New England) can affect operation of major transmission lines and generating units in New England and Massachusetts. Under certain circumstances, the loss of units outside of Massachusetts could lead to outages within Massachusetts. While it is impossible to eliminate the risk of events that could lead to outages in Massachusetts, it is possible to reduce the risk of large scale outages through appropriate operations and maintenance practices.

The Task Force recognizes the fundamental importance of the reliability standards that govern the planning and operation of the New England electric system. Transmission system operation and maintenance practices are prescribed by the NERC and NPCC, and implemented through the ISO-NE with the voluntary compliance of operating electric companies. The Task Force notes that transmission owner compliance with NPCC standards is self-certifying and regulatory oversight of transmission company maintenance activities is limited in practice. Moreover, there is no regulatory oversight of the maintenance practices of generation in the restructured electric industry in Massachusetts. Therefore, the Task Force recommends that:

- Massachusetts, in coordination with ISO-NE and Massachusetts electric companies, should participate in the development and review of NERC/NPCC reliability standards.

- Massachusetts should - absent mandatory reliability standards and appropriate regulatory oversight - ensure that both generation and transmission owners comply with standards for equipment maintenance and availability as established, reviewed and revised by the NERC/NPCC.

4. Operator Response

As the events of August 14th demonstrated, the stability of New England's electric grid is critically dependent on the actions of system operators, as well as on infrastructure. The Interim Report suggests that the August 14th outage might have been averted if FE and MISO operators had been aware of the transmission line outages in FE's territory and were prepared to take compensating actions. Similarly, our examination of events in New England on August 14th revealed that aggressive operator intervention was crucial to the stabilization of the New England electric grid after it separated from the rest of the Eastern Interconnection.

On August 14th, operators, utilities, and generators throughout New England worked together to stabilize the New England bulk power system. ISO-NE, through the master/satellite structure, had sufficient information to analyze the system operation and take the necessary actions. While sufficient information was available to system operators on

August 14th, the Task Force notes that all available information on operation of the interconnected system is not accessible by all operators, especially information related to operation of control areas outside of New England. A direct need for access to all information has not been established; however, one of the concerns raised in the Interim Report was the limits on system operator perspective. The Task Force, therefore, recommends that:

- ISO-NE should present information to system operators in the master/satellite and local distribution control centers regarding the real-time operation of the New England transmission system, to the extent this information is available; and

- ISO-NE should present information to system operators in the master/satellite and local distribution control centers regarding operation of systems outside of New England, to the extent this information is available.

The Task Force recognizes the benefits that result from the operation of the New England electric system as a single control area and recommends that:

- Transmission owners with assets in Massachusetts should continue to support coordinated operational control and authority over the real-time operation of the transmission grid through the ISO-NE, or a successor organization.[55]

It is critical that all operators be trained to respond to unanticipated events that could threaten system stability. Multiple contingencies may arise when unrelated events affect related electric infrastructure. Operators may be able to manage multiple unrelated contingencies, particularly if there is a reasonable period of time between events; however, at some point, it may be necessary to drop load in order to secure the electric system as a whole. While ISO-NE and satellite operators performed very well under difficult circumstances on August 14th, the Task Force finds that additional training, focused on unusual and significant power system events, could only enhance the security of the Massachusetts electric system. The Task Force, therefore, recommends that:

- ISO-NE should provide continuing training of ISO-NE, satellites, and generator operators to ensure that roles and responsibilities are clear and that operators are prepared to respond to unusual and significant power system events. ISO-NE, in collaboration with Massachusetts electric companies and satellites, should develop training that focuses on incident management and communication; such training should be required for both primary and backup operators and should occur on a regular basis.

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[55] Pursuant to a FERC policy initiative relating to regional electric system operation, ISO-NE, with the New England transmission owners, has submitted a proposal to the FERC to form a RTO.

Advanced tools such as training simulators may be helpful. ISO-NE should continue to assess the effectiveness of operator training programs.

The events of August 14th also demonstrate the critical importance of the computer systems used by operators to monitor and control the electric system. The Task Force has visited the ISO-NE, REMVEC, and the NSTAR control centers and finds that operators generally have access to the appropriate system operations tools. However, the Task Force notes that reliance on state estimator and security analysis tools can be risky unless operators are certain they are working correctly, and suggest that use of additional tools could improve system security. The Task Force, therefore, recommends that:

- ISO-NE and Massachusetts electric utilities should investigate the costs and benefits of improved facilities and diagnostic tools and alarms for system operators.

- ISO-NE and satellites should continue to conduct audits of the reliability of control center computer systems.

IV. BLACKOUT RESPONSE PROCEDURES

Massachusetts, specifically, and most of New England, generally, was largely unaffected by the blackout that occurred on August 14, 2003. The Task Force recognizes, however, that certain combinations of events could lead to a widespread power outage, or even a complete blackout, in New England. It is appropriate to plan for such an event. This section reviews plans for electric system restoration following a complete system blackout and makes recommendations for strengthening those plans.

A. Restoration Procedures

System restoration is guided by requirements found in FERC, NERC, NPCC, NEPOOL and satellite control center documents and procedures. In addition, each transmission, distribution, and generation company has its own system restoration policies and procedures. In the event of a complete system blackout, the emphasis is on creating small stable islands (NERC basic minimum power systems) and tying these islands together, creating a larger and stronger system over time. Islands are created by starting and loading blackstart[56] units and then supplying power via transmission lines to non-blackstart generators to allow them to start and load. The priority in the initial stages of restoration is to establish a stable transmission system, rather than to restore maximum customer load. Load will be picked up

[56] Blackstart units are those generating units capable of starting without an offsite source of AC power.

as required to stabilize generation and control voltage; subsequent shedding of load may be required.

Key facilities to support the formation and synchronization of the basic minimum power systems are identified in NPCC guidelines. Key facilities are "selected generators, transmission elements plus control and communication facilities that are designated as essential in the Restoration Plan of the Control Area."[57] Key facilities and their critical components are maintained and tested in accordance with NPCC standards. Generating units which are capable of blackstart operations, and which the NEPOOL system restoration working group have identified as critical to system restoration, are required to test their capability annually and report those results to ISO-NE.

ISO-NE and its satellites follow a four phase plan to implement system restoration following a complete blackout:

1. <u>Phase 1 – Determining the Extent of the Disturbance</u>: This is the fact finding phase of the restoration process. During this phase, transmission system operators process all incoming information from supervisory control and data acquisition ("SCADA") indications and alarms, and from conversations with other control centers and field personnel. Valuable information also may be obtained from outside news sources. For safe restoration, it is essential to understand the extent of the event and the state of the system before proceeding to energize facilities. During this time, control centers staff their emergency operations organizations, dispatching available field personnel to priority substations, clearing load from transmission and distribution buses, and ordering on blackstart generators at staffed stations;

2. <u>Phase 2 – Restarting the System</u>: This phase encompasses the creation of basic minimum power systems or small islands and tying these islands together at the intra-satellite level. Satellite system operators continue to start blackstart units, provide station service power to non-blackstart generators via the transmission system, and pick up load as necessary. ISO-NE and the satellite control centers coordinate efforts to energize and establish the 345 kV transmission system backbone.

   Several priorities are addressed during Phase 2. The highest of these priorities is to supply off-site sources of AC power to nuclear generating stations to allow safe shutdown of those units. Another high priority is to supply off-site station service to the Northfield Mountain pumped storage facility, which will be

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57 NPCC document B-20.

needed in Phase 4 to synchronize the New England control area with the New York control area;

3. Phase 3 – Reestablishing Inter-Satellite Ties: During this phase, ISO-NE coordinates with the satellite control centers to synchronize and tie islands together between satellite areas. This phase is not necessarily delayed until completion of Phase 2; rather, these ties are made as early in the restoration process as possible. This phase allows the additional generation capacity and available reserves to permit restoration of more customer load; and

4. Phase 4 – Reconnecting to NYISO: When it is desirable to reestablish an interconnect between the New England control area and the New York control area, the respective ISOs coordinate synchronizing electrical frequencies and tying the two areas together.

This four-phase plan is incorporated in the NEPOOL and satellite restoration procedures. Each satellite conducts training appropriate for its operators on their specific procedures and their role in system restoration. In addition, ISO-NE and the system restoration working group conduct an annual workshop at which participants from ISO-NE, the satellite control centers, and members of transmission, distribution and generation companies review and are trained on the overall system restoration plan. The workshop includes a mock system restoration exercise.

The duration of system restoration activities is dependent on (1) the extent of the disturbance and of any damage that preceded or occurred as a result of the blackout, (2) the availability of generators to start and synchronize to the grid, (3) the availability of personnel to staff substations, and (4) other factors. During the August 14th event, the collapse in New England was limited essentially to southwest Connecticut. Although New England was an island during that event, it was a large and stable one with sufficient generation and strength to allow restoration of the blacked out areas from the remaining energized system. A blackout affecting greater portions (or all) of New England would be more complex and, therefore, likely longer and more difficult to restore. The first phase of system restoration (determining the extent of the disturbance) typically is expected to take one to two hours, as it may take this long to obtain an accurate picture of the state of the system. This estimate was borne out by experience on August 14th. Industry experience shows that days may be required for total system restoration following large scale blackouts. Heavily damaged transmission or generation facilities may delay restoration significantly.

B. Communications During a Blackout

During a blackout, it is essential for the control centers (ISO-NE, satellites, transmission companies, distribution companies, etc.), field personnel at substations or elsewhere, and generator operators to be able to communicate. Communications are necessary to coordinate actions between control centers, dispatch staff to field locations, direct the operation of system components, and start or stop generators.

Difficulties with communication systems may be encountered. Land-line and cellular phone bandwidth tends to be consumed quickly during any catastrophic event. Telephone company facilities may themselves be damaged independent of, or as a result of, the blackout. For this reason, operators have available various means of communication, including land-line telephone, cellular telephone, satellite telephone, microwave communication and radio. Back-up communication systems exist for blackstart and other key generators. Field personnel may be contacted via substation land-line, cellular phone or radio.

Restoration procedures also provide that authorities will shift and certain actions will take place when communication is lost. For example, if communication is lost to ISO-NE, authority for generation dispatch and frequency control reverts to the satellites, allowing inter-satellite and inter-pool ties to be made without the ISO's permission.

C. Public Safety and Emergency Response

Although the Commonwealth's public safety response is outside the scope of this investigation, the Task Force recognizes the importance of Massachusetts' ability to respond to a prolonged outage or other incident without damage to property or loss of life. To this end, the Commonwealth's emergency management and public safety agencies have the authority and specific plans in place to respond to an emergency situation or other incident. Specifically, the Commonwealth's emergency management and public safety response to a prolonged outage or any other incident is governed by the State Comprehensive Emergency Management Plan ("SCEMP").[58]

Under the SCEMP, in the case of an emergency, appropriate federal, state, local, utility and other private industry representatives are required to report to the State Emergency Operation Center ("SEOC") in Framingham to pre-established emergency support function ("ESF") teams. Each ESF team is made up of state agencies and private industry representatives with common expertise and resources in their respective functional areas. Under the direction of a lead coordinating agency, ESF teams are tasked with collecting

58 In addition, the DTE requires that electric distribution companies maintain detailed emergency response plans that, among other things, stipulate employee and workgroup responsibilities and delineate distribution company procedures during and immediately after a declared emergency. See Western Massachusetts Electric Company, D.P.U. 95-86 (1995); Investigation re: Service Interruptions by Hurricane Bob, D.P.U. 91-228 (1992).

intelligence and providing resources to assist in responding to the emergency situation or other incident. Members of the ESF teams have direct authority to access their organization's resources in the case of an emergency. ESF teams train on a monthly basis at the SEOC. The SCEMP and the ESF teams are organized and have the same functions as their national counterparts under a national response plan. In conjunction with the SCEMP, individual communities follow procedures outlined in their Community Comprehensive Emergency Management Plans and coordinate their response with the SEOC.

The SCEMP is designed to provide a centralized, comprehensive and coordinated federal, state and local response to an emergency situation or other incident. In extreme cases, the Governor also has the authority under the Massachusetts Civil Defense Act[59] to declare a state of emergency and to deploy state resources to further protect the citizens and property of the Commonwealth.

D. Recommendations

Fortunately, ISO-NE and its satellites have not been called upon in recent years to implement system restoration following a complete blackout. However, the Task Force offers the following observations based on existing system restoration plans:

ISO-NE and the New England electric companies ensure readiness to respond to a New England-wide blackout by conducting an annual restoration exercise. This exercise ensures that all electric industry participants - master and satellite operators, transmission companies, distribution companies, and generators - understand what steps need to be taken and in what order to restore power to New England following a blackout. The exercise does not, however, address communications with the natural gas and telecommunications industries. During a major outage, coordination with these industries could be critical. The Task Force, therefore, recommends that:

- Massachusetts electric, gas, and telecommunications companies, and ISO-NE should explore opportunities to conduct a joint blackout restoration exercise similar to that conducted annually by New England electric providers.

Most major generating units are not capable of starting without an off-site source of power. Following a system-wide blackout, these generators cannot be brought on-line until some power has been restored to the electric grid by blackstart units. The Task Force finds that sufficient, properly located blackstart units are currently available to restore power

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59 Pursuant to G.L. c. 25A § 8, the Governor may also declare an energy emergency due to "actual or imminent severe supply interruption". After declaration of an energy emergency, the Governor may implement an energy supply shortage contingency plan.

following a system-wide blackout. However, many older generating units in Massachusetts, including at least one blackstart unit, are currently proposed for retirement. Blackstart units are required to provide a one year notice to ISO-NE before retiring the resource from the blackstart program. In response to a notice for retirement, ISO-NE assesses whether adequate blackstart resources will exist without the unit. In order to ensure that the ability to restore power following a system-wide blackout is not compromised by these retirements, the Task Force recommends that:

- ISO-NE and the satellite control centers should continue to review whether there are adequate blackstart resources to restore electric service to New England in a reasonable time following a widespread blackout.

The system restoration process, by its nature, involves switching operations at many different locations. The process may be made somewhat more efficient if more of these switching operations could be performed from a remote location. The Task Force, therefore, recommends that:

- Massachusetts electric companies should continue to develop the capability to remotely control T&D facilities.

SUMMARY OF RECOMMENDATIONS
ELECTRIC SYSTEM WORKING GROUP

- Massachusetts should participate actively in ongoing regional transmission planning activities and monitor the resolution of reliability issues identified through these activities.

- Massachusetts should closely monitor the resolution of emerging reliability issues in northeastern Massachusetts, particularly Boston.

- The DTE, the Siting Board, and other interested parties should review all phases of the transmission siting process to determine whether it can be streamlined while protecting the integrity of the public review process and the interests of ratepayers, abutters, other affected parties, and the environment.

- Massachusetts should explore opportunities to create, through state and regional policy formulation and implementation, as well as system oversight, a more stable, more reliable electric system through investments in conservation, energy efficiency and DG. Where institutional or regulatory barriers inhibit such investments, Massachusetts should seek to eliminate these barriers while protecting the interests of the ratepayers.

- Massachusetts should continue policies that encourage the development of renewable resources in order to advance the goal of a diverse generation base.

- Massachusetts, in coordination with ISO-NE and Massachusetts electric companies, should continue to review locations where a concentration of infrastructure creates a significant reliability risk and make practical recommendations for reducing the risk of disruption at those locations.

- Massachusetts, in coordination with ISO-NE and Massachusetts electric companies, should participate in the development and review of NERC/NPCC reliability standards.

- Massachusetts should - absent mandatory reliability standards and appropriate regulatory oversight - ensure that both generation and transmission owners comply with standards for equipment maintenance and availability as established, reviewed, and revised by the NERC/NPCC.

- ISO-NE should present information to system operators in the master/satellite and local distribution control centers regarding the real-time operation of the New England transmission system, to the extent this information is available.

- ISO-NE should present information to system operators in the master/satellite and local distribution control centers regarding operation of systems outside of New England, to the extent this information is available.

- Transmission owners with assets in Massachusetts should continue to support coordinated operational control and authority over the real-time operation of the transmission grid through the ISO-NE, or a successor organization.

- ISO-NE should provide continuing training of ISO-NE, satellites, and generator operators to ensure that roles and responsibilities are clear and that operators are prepared to respond to unusual and significant power system events. ISO-NE, in collaboration with Massachusetts electric companies and satellites, should develop training that focuses on incident management and communication; such training should be required for both primary and backup operators and should occur on a regular basis. Advanced tools such as training simulators may be helpful. ISO-NE should continue to assess the effectiveness of operator training programs.

- ISO-NE and Massachusetts electric utilities should investigate the costs and benefits of improved facilities and diagnostic tools and alarms for system operators.

- ISO-NE and satellites should continue to conduct audits of the reliability of control center computer systems.

- Massachusetts electric, gas, and telecommunications companies, and ISO-NE should explore opportunities to conduct a joint blackout restoration exercise similar to that conducted annually by New England electric providers.

- ISO-NE and the satellite control centers should continue to review whether there are adequate blackstart resources to restore electric service to Massachusetts in a reasonable time following a widespread blackout.

- Massachusetts electric companies should continue to develop the capability to remotely control T&D facilities as cost-effective.

REPORT OF THE NATURAL GAS WORKING GROUP

I. INTRODUCTION

Electric system reliability depends, in part, on the interconnectedness of the electric system and gas supply within the Commonwealth and the six-state New England region.[60] This section examines the strength of this interconnectedness by considering the following issues: (1) the extent of gas-fired generation in the region; (2) the current and projected natural gas infrastructure; (3) the sources of natural gas supply; (4) the deliverability of natural gas to the region; (5) the causes of and responses to natural gas interruptions; and (6) mechanisms for communications between the natural gas and electric sectors. This section concludes with recommendations that will assist in maintaining the essential relationship between the electric system and gas supply.

In summary, natural gas has become the leading fuel for power generation in Massachusetts and New England. The region's natural gas infrastructure has grown considerably in recent years, with the addition of new pipelines from Canada and enhancements to the existing pipeline grid. Also, the region's sources of gas supply have diversified in recent years, contributing to a more reliable gas delivery system. The growth in natural gas infrastructure and diversified natural gas sources help mitigate against potential disruptions in fuel supply and delivery and, consequently, increase the electric system's reliability. Maintaining and enhancing the region's natural gas infrastructure and diversity will support electric power reliability.

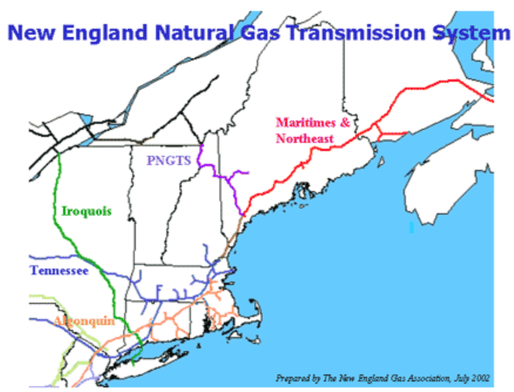

Figure 11 - New England Gas Transmission System

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60 A primer on the components of the natural gas delivery system is attached in Appendix D. See also Appendix I, Additional Comments of the Conservation Law Foundation and MASSPIRG.

II. GAS-FIRED GENERATION OF ELECTRICITY

A. Introduction

The extent to which a gas supply interruption could lead to a power outage depends on the extent to which gas is used to produce electricity. This section addresses the following topics regarding the level of gas-fired generation of electricity in New England: (1) the sources of energy in New England; (2) the currently projected fuel mix for electric generation; and (3) peak day gas requirements.

B. The Sources of Energy in New England

The primary fuel sources of electric generation in New England are natural gas, nuclear, coal, and oil.[61] As shown in Figure 12, below, natural gas represented 38 percent of fuel used for available electric generation in New England for the summer of 2003.[62] In addition, some electric generation facilities are dual-fuel capable.[63]

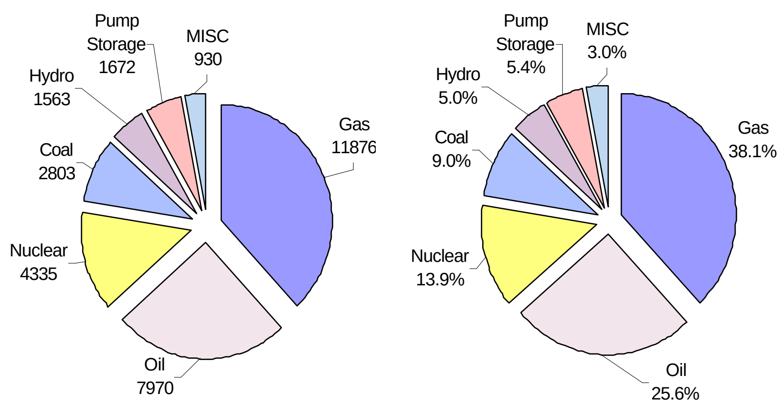

Figure 12 - New England's Installed Capacity by Primary Fuel Type as Assumed in the RTEP03 Report, Summer 2003, MW and Percent

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61 Appendix E sets forth each of the generating units in New England by sub-area and shows the primary fuel type.

62 Natural gas is expected to fuel 49 percent of New England's generation by 2010. Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket, Report of ISO New England Inc., July 1, 2003, p. iv.

63 For the years 2003 - 2004, the capacity of dual-fueled (oil/gas) capable power plants was approximately 7,075 MW in summer and 7,824 MW in winter.

As shown in Figure 13, below, power generation is projected to be the fastest growing sector for natural gas demand in New England through 2010. Since 1998, a total of 9,396 MW of new installed generation have been added, of which approximately 98 percent is natural gas capable. Of this quantity, 100 percent is primarily fueled by natural gas and six percent has dual-fuel capability.[64]

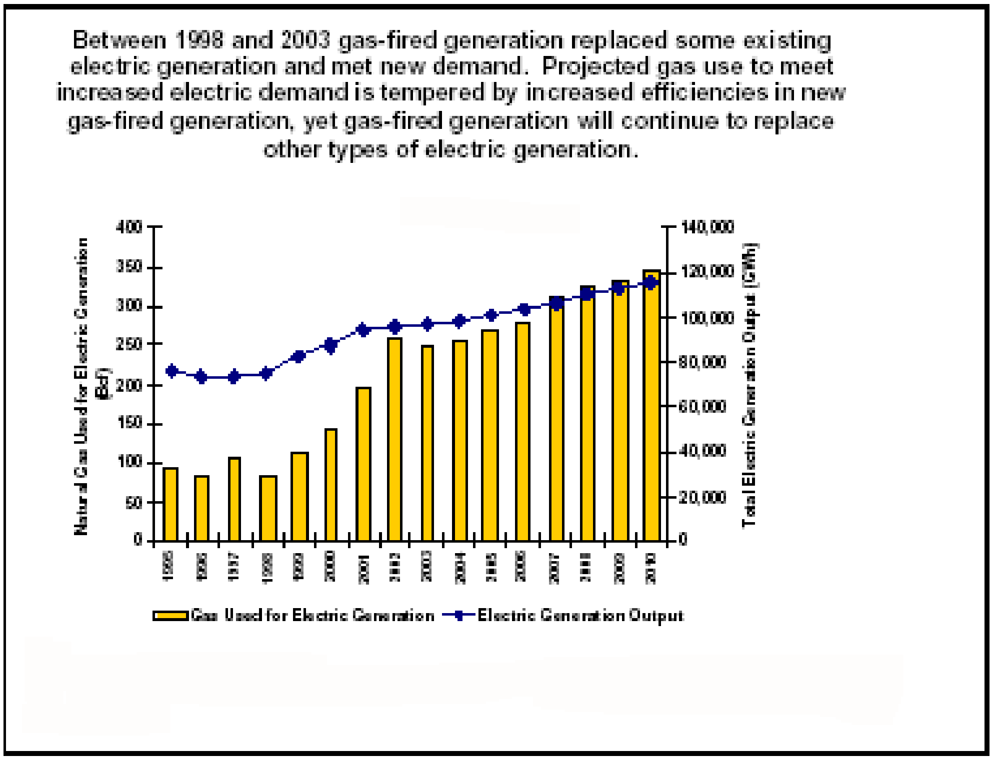

Figure 13 - **New England Natural Gas Infrastructure Report (FERC Report December 2003)**

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[64] Source: <u>ISO-NE New Generation Report</u>.

C. Fuel Mix

Over the next ten years, the use of natural gas to fuel electric generation is projected to increase. ISO-NE projects that NEPOOL gas-fired generation will increase from 40 percent, to approximately 50 percent over the next ten year period. Table 5, below, shows the projected increase.[65]

	COAL		DISTRIBUTED GENERATION		GAS		RENEWABLE		RESIDUAL FUEL OIL		URANIUM		WATER	
Year	**GWH**	**%**	**GWH**	**%**	**GWH**	**%**	**GWH**	**%**	**GWH**	**%**	**GWH**	**%**	**GWH**	**%**
2003	19954	16.4	0	0.0	50378	41.3	7185	5.9	4849	4.0	33321	27.3	6247	5.1
2004	19977	16.0	0	0.0	48092	38.4	7244	5.8	10328	8.2	33322	26.6	6260	5.0
2005	19994	15.8	0	0.0	56864	45.0	7166	5.7	2851	2.3	33322	26.4	6234	4.9
2006	20003	15.7	0	0.0	60683	47.5	7167	5.6	398	0.3	33322	26.1	6228	4.9
2007	20005	15.4	0	0.0	62584	48.2	7163	5.5	409	0.3	33322	25.7	6232	4.8
2008	20005	15.2	1	0.0	64298	48.7	7163	5.4	968	0.7	33322	25.2	6231	4.7
2009	20005	15.0	1	0.0	65485	48.9	7167	5.4	1576	1.2	33322	24.9	6228	4.7
2010	20025	14.7	1	0.0	67331	49.5	7161	5.3	1827	1.3	33322	24.5	6230	4.6
2011	20087	14.5	1	0.0	69165	50.1	7170	5.2	2087	1.5	33322	24.1	6227	4.5
2012	20156	14.3	2	0.0	70744	50.3	7168	5.1	3056	2.2	33322	23.7	6229	4

Table 5 - Projected (2003 - 2012) Generation Contribution by Fuel Type

65 Source: ISO-NE RTEP03 Technical Report.

D. Peak Day Gas Requirements

From 2003 to 2012, peak day[66] gas consumption is projected to increase correspondingly with the increase in load forecast. Table 6, below, shows the projected peak day gas consumption for aggregate gas-fired generation in NEPOOL.[67]

Year	Forecast of Summer Peak Day Gas Consumption for NEPOOL in Million Cubic Feet Per Day (MMcf/D)
2003	1,763.3
2004	1,784.4
2005	1,881.2
2006	1,931.5
2007	1,952.6
2008	2,001.1
2009	2,024.8
2010	2,058.9
2011	2,075.5
2012	2,111.3

Table 6 - Forecast of Summer Peak Day Gas Consumption for NEPOOL

E. Summary

The data show that 38 percent of the installed electric capacity in New England currently uses natural gas as its primary fuel source. The data also show that the use of natural gas is projected to increase over the next decade and will account for over 50 percent of electric energy production by 2012. In addition, natural gas reliance in the transmission-constrained greater Boston area is forecast to reach 80 percent by 2010.[68] This increasing use of natural gas requires monitoring of (1) the demand for electricity, (2) the supply of natural gas, (3) the growth in pipeline infrastructure, and (4) the primary fuel type of electric generation.

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66 Peak day refers to that day during which the greatest amount of gas is used.

67 Source: ISO-NE RTEP03 Technical Report.

68 Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket, Report of ISO New England Inc., July 1, 2003, p. v.

III. NATURAL GAS INFRASTRUCTURE

A. Introduction

The natural gas infrastructure (or capacity) used to supply natural gas for power plants includes interstate and intrastate pipelines, liquefied natural gas ("LNG") facilities,[69] and underground storage facilities. This section examines the capacity of existing gas infrastructure and identifies some infrastructure projects that are in various stages of development.

B. Capacity of Existing Gas Infrastructure

The total capacity of the region's existing natural gas interstate pipeline is approximately four billion cubic feet[70] per day ("Bcf/d"). The interstate pipeline capacity into New England has doubled since 1990. The daily pipeline capacity into New England of the interstate gas transmission pipelines is shown in Table 7, below.

Pipeline	Bcf/D
Algonquin Gas Transmission Company	1.600
Tennessee Gas Pipeline System	1.574
Maritimes & Northeast Pipeline	0.440
Iroquois Gas Transmission System	0.244
Portland Natural Gas Transmission System	0.220

Table 7 - Interstate Gas Transmission Pipeline Capacity

The interstate pipeline companies serving the region have completed several recent projects to bring further supplies to Massachusetts and New England. Two new pipelines transporting supplies from Canada have begun operation in the last five years: Portland Natural Gas Transmission System in 1998, and Maritimes & Northeast Pipeline, L.L.C. ("Maritimes & Northeast") in 1999. At the same time, other pipelines systems, such as

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[69] LNG is natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

[70] A Bcf is approximately ten million therms.

Algonquin Gas Transmission Company ("Algonquin") and Tennessee Gas Pipeline Company ("Tennessee"), have added compression and expanded pipeline capability on their systems within the region. In recent years, Tennessee has implemented such projects as "Eastern Express," "Londonderry Lateral," and the "RISEP Compressor." In the fall of 2003, Maritimes & Northeast completed its "Phase III Expansion" project extending the pipeline to Beverly. Also in the fall of 2003, Algonquin completed the new "HubLine" project connecting its pipeline system at Weymouth, by way of an offshore route, to an interconnect with the Maritimes & Northeast Pipeline Phase III facilities in Beverly.

There are no underground natural gas storage facilities in Massachusetts or New England; however, LNG storage has played a significant role in our natural gas market. In continuing to meet the gas supply needs of the region, a review of important factors such as safety concerns to the affected region(s) and the associated costs to deliver LNG should be considered. LNG represents approximately 30 percent[71] of the winter design day[72] requirements of the New England local gas distribution companies ("LDCs"). As with the increased interstate pipeline capacity, the vaporization capacity of Distrigas of Massachusetts ("Distrigas"), the region's LNG import terminal located in Everett, has nearly doubled. Distrigas' import terminal has two storage tanks capable of holding the equivalent of 3.5 Bcf of natural gas in total. Distrigas recently increased its daily vaporization capacity from 435 thousand dekatherms per day ("MDth/d") to 700 MDth/d, with the capability to increase to a maximum of 1,000 MDth/d. A large part of that vaporization capacity feeds directly into the Algonquin and Tennessee systems as well as into a neighboring power plant (over 1,500 MW). Distrigas also can deliver by truck up to another 100 MDth/d from its facility to smaller LNG storage facilities located around the region.

C. Proposed Natural Gas Infrastructure Projects

1. Pipeline Projects

A summary of proposed pipeline projects in the northeast (New England and New York area) is provided below.[73]

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71 An additional five percent is supplied by vaporized liquefied petroleum gas ("LPG").

72 Winter design day refers to the coldest day for which the utility plans to provide reliable firm service.

73 Appendix F details proposals in New England and New York for natural gas projects. The Task Force did not assess the need for specific new infrastructure projects. Appendix F is provided for reference only.

1. Granted FERC Certificate, Under Construction: "Eastchester Extension," Iroquois Gas Transmission System.

2. Granted FERC Certificate, Delayed Pending Final Permits: (1) "Millennium Pipeline," Columbia Gas Transmission Corp., TransCanada, Westcoast Energy, MCN Energy Group; and (2) "Islander East," Duke/Algonquin Gas Transmission Company, KeySpan.

3. Granted FERC Certificate: "Dracut Expansion," El Paso/Tennessee Gas Pipeline.

4. Proposed: (1) "Northwinds Pipeline," National Fuel Gas Supply, TransCanada PipeLine; (2) "Freedom Trail Expansion Project," El Paso/Tennessee Gas Pipeline; (3)"Northeast ConneXion Project," El Paso/Tennessee Gas Pipeline; and (4) "Blue Atlantic," El Paso.

2. LNG Projects

Several proposals have been announced regarding import terminals for LNG, with two of these announced for Massachusetts.[74] Among the projects and locations are the following:

1. Weaver's Cove Energy, Fall River (sponsor - Weaver's Cove Energy, LLC);

2. Somerset LNG, Somerset (announced);

3. Providence LNG, Providence, Rhode Island (sponsors - KeySpan Corp. and BG LNG Services);

4. Fairwinds LNG, Harpswell, Maine (sponsors - TransCanada and ConocoPhillips);

5. Canaport, Saint John, New Brunswick (sponsor - Irving); and

6. Bear Head LNG Project, Point Tupper, Nova Scotia (sponsor - Access Northeast Energy Inc).

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[74] Appendix G details proposals regarding LNG import terminals in New England and eastern Canada. The Task Force did not assess the need for specific new projects. Appendix G is provided for reference only.

3. Variables to Project Development

These project lists are an indication of the gas industry's interest in the New England and northeast marketplace. Not all of these projects will develop, however. Several variables in energy project development may affect the ability to move forward, including:

1. Capital availability/financing;

2. Federal and state regulatory and environmental permitting;

3. Commitments from shippers;

4. Natural gas supply availability;

5. Length of the review process;

6. Economic conditions;

7. Changes in market demand;

8. Status of competing/alternate energy sources; and

9. Electric market rules and pricing signals.

D. Conclusion

The region's natural gas infrastructure is capable of meeting the current firm gas transportation contracts of gas-fired generating units. There are numerous proposals for future infrastructure developments to meet future market needs. Although not all projects will be pursued and completed, the expectation is that additional pipeline capacity and LNG supplies will be added over the next decade.

IV. NATURAL GAS SUPPLY

The availability of gas-fired generation is affected by the availability of natural gas supply. This section addresses the locations and outlook for supply receipts in the future.

Having no indigenous supply of natural gas, New England’s pipeline infrastructure has multi-directional gas flows which enhance supply accessibility and system reliability, delivering gas from four sources.[75] About 85 percent of the natural gas consumed in New England comes from North America, with approximately 42 percent from domestic resources and 43 percent imported from Canada. The remaining 15 percent of gas consumed in New England comes from imported LNG - a number that is growing. LNG imports historically came from Algeria and, since mid-1999, from Trinidad & Tobago.

Although the North American natural gas resource base is large and diverse, the September 2003 National Petroleum Council's ("NPC") natural gas study cautions against relying too heavily on the current status quo of domestic production.[76] That study suggests that future supply availability will have to consider increased LNG importation as well as new drilling sources.

V. DELIVERABILITY OF NATURAL GAS

A. Introduction

Natural gas is delivered to power plants through the interstate pipeline system under contract terms that provide for either firm or interruptible service. To help assess reliability in the case of a natural gas interruption, this section examines the levels of transportation service to power plants.

B. Types of Transportation Service

As shown in Figure 14, below, a power generator may contract for either firm or interruptible (also known as "non-firm") transportation service. Firm transportation service, the higher quality service, is not subject to prior claim by another customer. Firm transportation is a service for which pipeline facilities have been designed, installed and dedicated to a certified volume. The delivery of natural gas to a power generator with a contract for firm transportation will take priority over the delivery of natural gas to a power

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75 The FERC New England Gas Infrastructure Study, December 2003, p. 4 states that while "[d]iversification helps to ensure some supply of natural gas even if there is a disruption from any single source, none of these sources alone can fully meet New England's natural gas demand. Further, being remote from the source of supplies, access to gas supply and storage is limited by pipeline capacity during periods of peak demand."

76 "Traditional North American producing areas will provide 75 [percent] of long-term U.S. needs, but will be unable to meet projected demand. Without new drilling, U.S. production declines by 25-30 [percent] each year." NPC Natural Gas Study, Volume 1, Summary of Findings and Recommendations, September 2003. p. 30.

generator with interruptible service. Firm service ensures transportation under almost all circumstances.

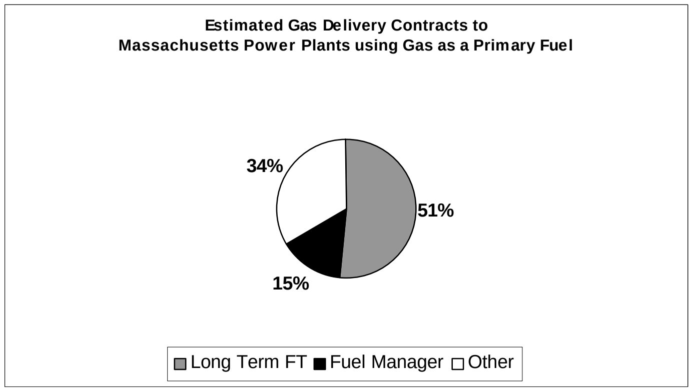

Figure 14 - Estimated Gas Delivery Contracts to Massachusetts Power Plants using Gas as a Primary Fuel

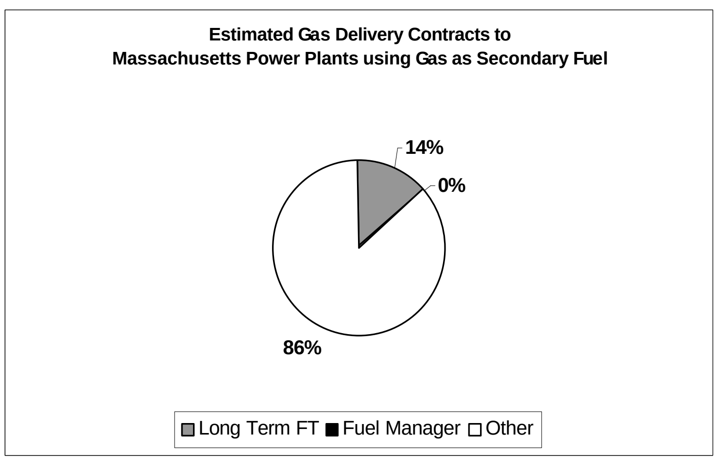

Figure 15 - Estimated Gas Delivery Contracts to Massachusetts Power Plants using Gas as Secondary Fuel

NOTES: "Other" includes short term firm transportation contracts, pipeline capacity release, interruptible transportation, and firm and spot sales where gas is delivered by the seller. Gas-Fired Power Plants are plants for which natural gas is the primary fuel.

SOURCE: Based on data developed by Merrimack Energy for the December 2003 FERC staff report on New England Natural Gas Infrastructure.

The types of transportation contract service may affect the deliverability of gas.[77] Interruptible transportation service is subject to interruptions when deliveries would interfere with, or restrict, other deliveries having higher priority. Therefore, interruptible service includes in its contract terms the possibility of interruption under certain operational and market conditions. To that extent, firm versus non-firm levels of transportation service, as contracted for by the shipper, can impact reliability of delivery to end-users such as power generators.[78]

Those who contract for and pay for primary, firm transportation will receive their transportation first as planned, approved, and scheduled. The inability of some generators to secure gas on any given day does not necessarily result from a shortfall in gas supply or gas transportation capacity, but may be the result of contract terms. At the same time, other factors such as overall electric system generating capacity levels and electric market price signals can contribute to generators' decisions at certain times to sell their gas into the marketplace rather than use it for the generation of electric power. These are economic decisions of market participants and do not necessarily represent the adequacy or lack thereof of the natural gas infrastructure.[79]

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[77] Generation companies are not mandated to report the nature of contracts (firm or interruptible) to regulatory authorities. Generation companies declined to provide these data because of its proprietary nature. Figure 14, based on data developed by Merrimack Energy for the FERC Staff Report of December 2003, represents the best estimate of the percent of firm versus interruptible contracts for Massachusetts' gas-fired power plants.

[78] See Appendix H for a discussion of the rationale and risks of firm versus interruptible gas transportation contracts.

[79] ISO-NE, in consultation with FERC and the New England regulators, is reviewing market rules, participant behavior, and operational procedures, as related to reliability. ISO-NE has initiated a review of system operations, wholesale electricity market results, and dependencies with the natural gas market. ISO-NE will be working closely with the FERC, the New England Conference of Public Utilities Commissioners, market participants, and the gas industry to ensure that market rules and operating procedures during extreme winter weather conditions are consistent with bulk power system reliability and efficient markets.

As discussed above, both the pipeline system and the supply of gas are adequate to provide service for electric generation with firm transportation contracts. The type of contract (i.e. ,whether the contract is firm or interruptible) may affect the delivery of gas. While an interruptible contract may be restricted, the flow of gas is not routinely interrupted during non-peak periods. However, during peak winter periods, interruptible transportation contracts are more frequently subject to restriction in order to meet the contact requirements of the firm transportation customers. Because of the mild winters experienced in recent years, restrictions of interruptible contracts during the winter period had been infrequent. However, as evidenced during the extreme winter conditions of January 2004, all customers with firm transportation contracts were scheduled, and nearly all interruptible transportation contracts were interrupted. The reliability of generation subject to interruptible transportation contracts may become an issue during peak winter periods because these contracts may experience more frequent interruption of service.

VI. NATURAL GAS INTERRUPTIONS

A. Introduction

Natural gas interruptions occur when supply or transportation of the commodity is disrupted. This section will discuss the causes of and response to natural gas interruptions.

B. Causes of Gas Supply/Transportation Interruptions

The potential causes of interruptions in gas supply and/or transportation could include:

1. Capacity constraints: Capacity constraint refers to points on the system where the delivery through the pipeline system is "constrained" due to the intersection of high demand and maximum available capacity. System bottlenecks may be part of the reason;

2. Operational Flow Orders: Operational flow orders ("OFOs"), also known as system emergency orders or critical period measures, are issued by a pipeline to protect the operational integrity of the pipeline. The orders may either restrict service or require affirmative action by shippers;

3. Weather: Severe storm weather may affect shipping, affect fuel delivery via roadways (LNG, propane and heating oil), shut-in production off-shore, and cause wellhead freeze-ups;

4. Catastrophic events: Explosions or other failures, earthquakes, hurricanes, or other severe storms may cause the loss of a major pipeline segment;

5. Electric power interruptions: The loss of electric power to computer systems or compressors operating on electricity may affect components of the natural gas delivery systems. An electric power outage could cause turbines to come on-line suddenly when there was no expectation of use, quickly using up available pipeline line-pack,[80] affecting local pressure and flexibility;

6. Failures of system components: Failures of system components includes shut-in production, loss of a compressor station, and outage of a pipeline segment because of undetected internal or external damage;

7. Third-party damage: Third-party damage (e.g., contractors striking a gas line) may affect gas flow in particular areas;

8. Shipping restrictions: Restrictions on cargo ships carrying LNG could drastically reduce New England's access to LNG supplies. Restrictions could range from ship operational problems to potential harbor freezes or bans on ships entering the harbor (as occurred during the fall of 2001 in Boston Harbor for reasons of homeland security); and

9. Mandated facility shutdowns: The government may mandate that a facility or facilities be shut down for reasons relating to homeland security.

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[80] Packing the line increases the amount of gas in the system by adding gas and/or increasing pressure. Drafting the line decreases the amount of gas in the system by decreasing gas and/or decreasing pressure.

C. Response to Interruptions

The components of the natural gas industry work together to ensure system security and fuel delivery. At times of gas supply constraints, the components of the industry communicate and work together to coordinate movement of supplies.

Unlike the delivery of electricity, the delivery of natural gas is not dispatched by a central body - there is not a "natural gas ISO." However, the New England region has a gas supply coordinating mechanism known as the Gas Supply Task Force ("GSTF"), administered by the Northeast Gas Association ("NGA," formerly New England Gas Association). Established over 20 years ago, the GSTF monitors regional gas deliverability during the winter heating season. Members include all the pipelines serving the region, the major LDCs, Distrigas, LNG trucking companies, and, beginning in 2002, several of the larger power generators with extensive gas transportation contracts. The GSTF is a backstop to ensure security of supply delivery within the region at times of supply or delivery constraint. The first obligation of each company in the region is to take all reasonable steps to mitigate its particular supply or delivery problem. If the problem is beyond the scope of that company, the company may request that the GSTF be convened to consider a regional response.[81] NGA informs state regulatory officials of the GSTF's actions.

VII. COMMUNICATIONS WITH ELECTRIC SECTOR

During times of gas supply constraints, electric and gas industry participants together facilitate the movement of gas supply. This section addresses the mechanisms currently in place to facilitate communication and coordination between the gas and electric system operators in times of emergency on either system.

In conjunction with representatives of the natural gas industry, ISO-NE has developed an internal document entitled, Natural Gas Operations in New England – Emergency Information Package, revised March 20, 2003. This document is available to ISO-NE control room system operators and includes emergency contact information for the five interstate pipelines serving New England, Distrigas, New England's LDCs, and the NGA. In addition, the document provides spreadsheets detailing gas-fired generation by pipeline/LDC as well as natural gas pipeline maps detailing the New England infrastructure.

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81 In recent years, the GSTF convened on a few occasions. In January 2000, during an extended cold snap, it facilitated the transfer of LNG supplies among several LDCs. In September/October 2001, the GSTF monitored the temporary shutdown of the Distrigas facility following a Coast Guard directive after the September 11th attacks, for the purpose of assessing LNG supply disruptions to the region as winter approached.

Further, ISO-NE has taken several steps and initiatives to increase education, understanding, and coordination with all representatives of the natural gas industry. For example, ISO-NE has joined the NGA as an associate member. In addition, ISO-NE is represented on the NERC Gas/Electric Interdependency Task Force ("GEITF"), recently formed to assess issues such as scheduling and communications protocols. As the natural gas and electric markets become more interdependent, it would be helpful for industry segments to develop improved and more formalized procedures for communications between the gas and electric industries. The electric generation and gas industries are working together to ensure safe and reliable delivery of natural gas to all gas consumers.

Similarly, the NGA has instituted mechanisms for facilitating communication among system operators. NGA, through the GSTF, brings together the elements of the gas industry and the larger power generators. NGA also has worked closely with ISO-NE through NGA's Power Generation Advisory Committee.

Nationally, the electric and gas industries are working together through the North American Energy Standards Board ("NAESB"), which serves as "an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities."[82] NAESB is organizing a Gas Electric Coordination Task Force ("GECTF") to review and investigate the possible creation of standards related to the coordination between the scheduling of electric and gas transactions.[83]

VIII. CONCLUSIONS

Natural gas has become the primary fuel for power generation in Massachusetts and New England. In 1980, natural gas represented one percent of the regional fuel mix capacity; in 2003, natural gas represents 38 percent. Projections indicate that natural gas could represent 50 percent of the electric energy production in the next decade. Massachusetts and New England have added substantial new natural gas-fired electric generation in recent years, thereby increasing the region's installed capacity.

The region's natural gas infrastructure has grown considerably in recent years, with new pipelines from Canada and enhancements to the existing pipeline grid. Also, the region's LNG import facility has grown in capacity and begun fueling the region's largest power plant

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82 See NAESB web page: http://www.naesb.org.

83 Information about the January 29-30, 2004 meeting of the GECTF may be found on the NAESB website: http://www.naesb.org/gas_electric_coordination.asp.

(located in the greater Boston area). The region's sources of gas supply have also diversified in recent years, contributing to a more reliable gas delivery system.

Studies by ISO-NE indicate adequate gas pipeline deliverability to meet summer electric demand from gas-fired generators; however, these studies also indicate a tighter gas supply/demand balance exists in the winter, especially on peak demand days. At the same time, the electric reserve margin in the winter is higher than in the summer - the peak demand period for electricity in New England. In other words, the portion of the electric needs satisfied with natural gas in the winter period is lower than in the summer period.

A diversity of generating sources helps mitigate against potential disruptions in fuel delivery from any one source. This would include demand-response and efficiency programs, as well as renewable energy sources and DG.

Fuel-switching by gas-fired generators to oil backup may be an option for greater reliability. However, there are many challenges including: (1) the declining capacity of the region's oil storage facilities; (2) environmental restrictions; (3) transportation and operational issues; and (4) local opposition. Also, sufficient market signals have not been present for power generators to bear the cost of oil storage and oil supplies at their facilities.

Firm versus interruptible levels of natural gas transportation, storage, and supply services may affect the delivery of natural gas to power generators. Long-term transportation contracts by power generators will provide incentives for gas pipeline companies to make investments in infrastructure.

There are several proposals for new projects to increase the region's gas supply and delivery capacity over the next several years, from offshore production, storage and pipeline enhancements, to new LNG import terminals. Challenges include: (1) the preference of many power generators for shorter term and interruptible contracts, which reduce incentives for project financing; and (2) the siting of new energy facilities.

Maintaining and enhancing the region's energy infrastructure, including electric generation, transmission, and distribution, combined with natural gas pipeline and LNG storage, while also increasing efficiency measures, are central to increasing energy grid reliability in the Commonwealth.

SUMMARY OF RECOMMENDATIONS
NATURAL GAS WORKING GROUP

- Massachusetts and the gas industry should promote continued increases in pipeline capacity and deliverability to bring new supplies into and within Massachusetts and New England to meet market demand, which will enhance overall energy system security and reliability. Additional LNG supplies may represent an important part of this supply mix.

- Massachusetts and the gas industry should encourage continued diversity of supply sources to enhance reliability.

- Electric and natural gas system operators should work to create greater communication and coordination in the region, which will help to ensure quick responses to emergency situations in either the gas or electric systems.

- Massachusetts and the gas industry should continue to encourage natural gas-related efficiency measures.

- Because firm versus interruptible contracts may affect the delivery of natural gas to power generators, ISO -NE should review the existing market rules and procedures to determine if appropriate pricing signals would ensure that the necessary levels of gas supply and transportation agreements are held by power generators, while adhering to market principles. This, in turn, will help ensure that gas-side infrastructure is developed where and when it is needed to enhance overall power system reliability.

- As it seeks to enhance overall bulk electric grid reliability, ISO-NE should review its existing market rules to ensure that proper incentives exist to promote a diversity of fuel sources used in generating electric power, including dual-fueled capability at generating stations.

REPORT OF THE TELECOMMUNICATIONS WORKING GROUP

I. INTRODUCTION

The Telecommunications Working Group examined the role that telecommunications facilities play in electric system reliability and the role of telecommunications in the electric system emergency response process. To a lesser extent, the Telecommunications Working Group examined telecommunications system reliability as it relates to the provision of services to electric companies.

The Interim Report did not identify telecommunications systems used by electric companies as a factor in the August 14th outage. Likewise, the Interim Report did not identify telecommunications systems as a hindrance to electric systems' restoration efforts. However, in order to provide a complete analysis, the Telecommunications Working Group has examined the role of telecommunications in electric system reliability and emergency response. Overall, the examination did not reveal major areas of concern. However, the Telecommunications Working Group did identify certain issues for which we offer specific recommendations and that may require further study.[84]

II. ROLE OF TELECOMMUNICATIONS IN ELECTRIC SYSTEM RELIABILITY AND EMERGENCY RESPONSE

Electric companies use telecommunications facilities and services for both voice and data communications to monitor power flows, control and restore equipment, protect high-voltage transmission lines (protective relaying), and communicate with service personnel. For protective relaying application, NPCC criteria dictate that redundant communications are required for certain high-voltage transmission facilities. Electric companies use their own internal network facilities, where available, to meet business requirements and also purchase telecommunications facilities and services from telecommunications providers for monitoring and control activities. For example, Western Massachusetts Electric Company uses a combination of its own microwave and fiber as well as leased microwave and fiber capacity from telecommunications providers. National Grid uses a combination of its own microwave and fiber facilities where available as well as leased analog and digital services from telecommunication providers for protective relaying and monitoring and control activities. NSTAR uses its own battery backup redundant fiber optic network for critical substations monitor and control, and relies on carrier services, purchasing dedicated lines to other electric substations and T1 lines between its dispatch centers. According to NSTAR, these external

84 ISO-NE did not participate in the Telecommunications Working Group. Therefore, this report does not address how telecommunications impacts the reliability and emergency response functions performed by ISO-NE.

leased lines and T1 lines are a critical communication network for the monitoring and control of electrical equipment. These communication lines remotely report back pending situations which could cause a power outage, loss of equipment, and power outages. These lines also enable NSTAR to take immediate emergency action which could prevent a more extensive outage. For instance, NSTAR states that these lines would remotely report information if transmission lines were being overloaded. NSTAR operators could then take immediate emergency action to control substation equipment to try and prevent a grid outage (i.e., voltage reduction or load shedding). Without these communication lines, NSTAR states that it could not remotely monitor its equipment or send remote control functions to its substation equipment. On a day-to-day basis, NSTAR relies on these telecommunication systems to restore services. During a major grid outage, similar to the August 14th event, NSTAR states that these communications links are critical.

Voice communications are used to communicate with field personnel to relay or receive information, to coordinate fieldwork, and to direct emergency response efforts. For example, NSTAR maintains an internal network to communicate with service personnel via in-vehicle radios or walkie-talkies. National Grid uses outsourced wireless services as a back-up to its internal two-way radio network. Western Massachusetts Electric Company, on the other hand, uses telecom-provided services for communications with its field personnel. Voice communications also are used to communicate with government officials during an emergency.

Some electric companies do not maintain redundant telecommunications facilities for monitoring, control, and restorative functions.[85] If remote monitoring and control facilities (either internal or external networks) experience an outage, NSTAR notes that the electric companies would have to dispatch service personnel to their more critical substations to manually operate the equipment. Because it typically takes 30 minutes to travel to a substation, this contingency works if the external communication goes down, but the electric system is still stable. Once service personnel are in the more critical substations, electric companies are in a better position to respond to emergencies. If the electric system was having outages or becoming unstable and the communications went down, NSTAR states that utilities would lose critical monitoring and control systems used to try and keep the system stable. NSTAR is continuing to transfer its more critical substations from external communication providers onto its own fiber optic communications. Western Massachusetts Electric Company notes that upgrading analog technologies with digital systems, such as frame relay, would allow it to automatically reroute communications over alternate facilities, in the event of a telecommunications outage and in the absence of backup facilities. National Grid states that it is testing frame relay connections and continues keep abreast of technology innovations, seeking appropriate opportunities to apply them.

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[85] National Grid states that it provides redundant communications for certain high-voltage facilities according to NPCC criteria.

The electric companies maintain backup arrangements in the event voice telecommunications experiences an outage, which include the use of wireless telephones, radios, or wireline telephones. However, the electric companies state that loss of their primary voice communications, notwithstanding backup systems, would in some instances mean relying on less effective means of communication.

III. EXTERNAL TELECOMMUNICATIONS NETWORK RELIABILITY

As noted above, electric companies rely on telecommunications networks to remotely monitor and control the electrical equipment within the power grid. For this reason, a single failure in the communications network could affect the transfer of data between the electrical equipment in the field and the corresponding operations and control centers. While some power companies provide their own internal communications network for monitoring and controlling their electrical equipment, others rely on external communications networks provided by telecommunications carriers. For those networks provided by telecommunications carriers, electric companies must rely on that carrier's outage preparedness plan to respond to any event that effects their ability to communicate with their equipment and personnel.[86]

All facilities-based telecommunications carriers have emergency response plans to assist in the restoration of their communications networks during a service outage. These emergency response plans identify the roles and responsibilities of individual corporate units and the procedures that employees must follow throughout an incident. Carriers select employees with specialized skills and training from within each corporate unit to serve as the primary point of contact for the network recovery efforts. Moreover, these employees participate in regional emergency response exercises conducted at the corporate level, as well as those carried out by government agencies. These exercises ensure that individuals are kept up-to-date with the

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86 While this report focuses on electric system outages, in the event of a telecommunications network outage it is important that electric companies obtain a Telecommunications Service Priority ("TSP") assignment or similar arrangement with their telecommunications carrier if they do not already have one. TSP is a Federal Communications Commission program managed and operated by the National Communications System under the Department of Homeland Security. A TSP assignment will ensure that electric company external communications services are restored before any non-TSP assigned service. Because of the electric companies' reliance on external communications networks to monitor and control their electric equipment, a TSP assignment or similar arrangement with their communications provider will assist with ensuring the stability of the electric grid in the event of a telecommunications network outage.

emergency response procedures and equipment, as well as the corresponding interaction with other emergency response personnel and agencies.

Telecommunications network reliability is dependent upon the uninterrupted supply of power to the telecommunications switching centers. To prepare against commercial power outages, carriers equip their central offices and remote terminals with emergency power supply systems. These systems consist of a combination of emergency power sources, portable generators, and batteries, depending on the importance of the location and the amount of equipment to be powered. Carriers conduct routine testing and maintenance on these back-up power supply systems to ensure their interoperability.

In central offices, carriers use a mix of standby/emergency generators and batteries for their back-up power supply needs. When commercial AC power is lost, standby generators start-up automatically to support the central office equipment.[87] In the event that an outage lasts longer than the generator's fuel supply, the carriers have agreements with fuel suppliers to provide around-the-clock fuel delivery upon request. Battery back-up power is deployed to provide instantaneous support to telecommunications equipment during a power outage. The batteries may carry the power load for a short period of time if the central office is equipped with a generator or for a longer period of time if there is no generator.[88] In the event that an outage lasts beyond the capacity of the batteries, carriers will dispatch technicians to those locations to provide additional back-up power using portable generators.

Unlike central offices, which are the local hub of the telecommunications network and house the majority of call processing equipment, remote terminals are part of the local loop and house digital loop carriers ("DLCs"), which combine the traffic from individual subscriber lines into one transmission path back to the central office or separate out the traffic sent from the central office to the individual subscriber. Because remote terminals are significantly smaller in size, carriers primarily use battery back-up power to support the DLCs during a power outage.[89] Just as in the central office, in the event that a power outage lasts longer than

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[87] Verizon sizes the fuel capacity of its generator to provide for 48 to 72 hours of operation.

[88] Verizon's network is designed such that DC power flows through the batteries to the equipment so that, in the event of a power outage, there is a seamless transition to battery power. The batteries are designed to last anywhere from four to eight hours for Verizon and eight to 32 hours for AT&T.

[89] Batteries that provide back-up power to the remote terminals have a similar capacity to those used in the central offices.

the battery supply, carriers dispatch technicians to deploy portable generators to serve the remote terminals' power needs.

IV. RECOMMENDATIONS

Without redundant or backup facilities for internal or external telecommunications networks, electric companies could be vulnerable to the loss of data or voice telecommunications facilities and services, which could impact their ability to prevent or respond to an electricity outage. Electric companies are large business customers of telecommunications carriers and, as such, carriers have the same incentive to provide very high quality, reliable telecommunications services to electric companies that they provide to all major business customers. The electric companies' contingency plans for loss of telecommunications services appear to be reasonable and appropriate and, as the electric companies note, telecommunications (or the loss of telecommunications) has never been the cause of a power outage to date. However, most large business customers whose business is dependent on a very high level of telecommunications reliability provide for redundancy in their telecommunications systems because no telecommunications facility can be provided with 100 percent reliability. Therefore, the Task Force recommends that:

- Electric companies and their telecommunications providers should carefully assess whether redundancy should be built into telecommunications networks, particularly for data communications.

- Electric companies and their telecommunications providers should work to upgrade their data and voice communications systems used for promoting electric system reliability and for emergency response to incorporate up-to-date, more flexible technologies.

- Electric utilities and their telecommunications providers should continue to study the issues of redundancy and upgrading their data and voice communications systems.

The Telecommunications Working Group also believes these issues would benefit from further study.

SUMMARY OF RECOMMENDATIONS
TELECOMMUNICATIONS WORKING GROUP

- Electric companies and their telecommunications providers should carefully assess whether redundancy should be built into utilities' telecommunications networks, particularly for data communications.

- Electric companies and their telecommunications providers should work to upgrade their data and voice communications systems used for promoting electric system reliability and for emergency response to incorporate up-to-date, more flexible technologies.

- Electric utilities and their telecommunications providers should continue to study the issues of redundancy and upgrading their data and voice communications systems.